SETTLEMENT AGREEMENT

FEBRUARY 4, 2008

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I. INTRODUCTION

This Settlement Agreement ("Agreement") is filed with the Ontario Energy Board ("OEB" or "Board") in connection with the EB-2007-0615 application ("Application") of Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") for an order or orders approving a revenue per customer cap as the Incentive Regulation ("IR") framework to be used for the purpose of setting of rates for the period from January 1, 2008 to December 31, 2012 ("IR Plan").

II. SETTLEMENT CONFERENCE

Procedural Order No. 5, dated August 31, 2007, provided for a Settlement Conference. A Settlement Conference was accordingly held from December 6 to December 18, 2007 and from January 2 to January 17, 2008, in accordance with the Board's *Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* ("Settlement Guidelines") in connection with the Application. This Agreement arises from the Settlement Conference.

Enbridge and the following intervenors (collectively, the "Parties"), as well as the Board's technical staff ("Board Staff"), participated in the Settlement Conference:

Association of Power Producers of Ontario ("APPrO")
Building Owners and Managers Association of the Greater Toronto Area ("BOMA")
Consumers Council of Canada ("CCC")
Coral Energy Canada Inc. ("Coral/Shell Energy")
Energy Probe Research Foundation ("Energy Probe")
Green Energy Coalition ("GEC")
Industrial Gas Users Association ("IGUA")
Jason F. Stacey
City of Kitchener ("Kitchener")
London Property Management Association ("LPMA")
Ontario Association of Physical Plant Administrators ("OAPPA")
Pollution Probe
Power Workers Union ("PWU")
School Energy Coalition ("SEC")
Sithe Global Power Goreway ULC ("Sithe")
City of Timmins ("Timmins")
TransAlta Cogeneration L.P. and TransAlta Energy Corp. ("TransAlta")
Vulnerable Energy Consumers Coalition ("VECC")
Wholesale Gas Service Purchasers Group ("WGSPG")

III. ISSUES

The Agreement deals with all of the issues listed at Appendix "A" to the Board's Procedural Order No. 4 dated August 13, 2007 (the "Issues List"). The Issues List is attached hereto as Appendix A. The Agreement also deals with the issues arising out of the Company's request for approval of its 2008 total revenue and corresponding 2008 rates for each customer class. These issues are not specifically enumerated in the Issues List but, nevertheless, are raised by the Application and supported by the evidence filed in the EB-2007-0615 proceeding.

IV. SETTLEMENT CATEGORIES

Each issue dealt with in this Agreement falls within one of the following two categories:

1. **complete settlement –** an issue in respect of which Enbridge and all of the other Parties who discussed the issue either agree with the settlement or take no position on the issue; and

2. **incomplete settlement –** an issue in respect of which Enbridge and at least one of the other Parties who discussed the issue are able to agree on some, but not all, aspects of the issue, such that portions of the issue will be addressed at a hearing.

Of the 34 issues in this proceeding, 33 are completely settled and only one component of one issue – Issue 5.1 – is incompletely settled.

V. PARAMETERS OF AGREEMENT

The description of each issue assumes that all of the Parties participated in the negotiation of the issue, unless specifically noted otherwise. Any Parties that are identified as not having participated in the discussion of the issue also take no position on any settlement or other wording pertaining to the issue.

Board Staff participated in the Settlement Conference. However, Board Staff takes no position on any issue and, as a result, is not a party to the Agreement. Although Board Staff is not a party to this Agreement, as noted in the Settlement Guidelines, "Board Staff who participate in the settlement conference are bound by the same confidentiality standards that apply to parties to the proceeding".

The structure and presentation of the Agreement are consistent with agreements which have been accepted by the Board in prior cases. The Agreement describes the agreements reached on the completely and incompletely settled issues. It identifies the Parties who agree or take no position on each of the issues. For the purposes of this Agreement, the term "no position" includes Parties who were involved in discussion of an issue but who ultimately took no position on that issue as well as Parties who did not participate in the negotiations with respect to that issue.

The Agreement lists the exhibits in the record pertaining to each completely settled issue. There are Appendices to the Agreement which provide further evidentiary support. The Parties agree that the Appendices form part of and are an essential component of the Agreement.

Appendices C through G comprise schedules that set out the Company's best estimates of distribution revenues, tax rate change impacts, assignment of distribution revenue to rate classes and rate and bill impacts for each rate class, in each year of the IR Plan (2008-2012). These estimates are derived from specific assumptions that Enbridge has made with respect to certain key variables such as volumes, customers and average use. Enbridge represents that these underpinning assumptions are not expected to materially change from the values used to derive the estimates. Accordingly, Enbridge also represents that there is a reasonable expectation that the estimated annual rate and bill impacts by rate class (Appendices F and G) arising from the application of the revenue per customer cap methodology, will materialize. Enbridge acknowledges that the Parties have relied on its representations with respect to the expected annual rate impacts and that their reliance thereon is material to their agreements with respect to the settled issues.

According to the Settlement Guidelines (p. 3), the Parties must consider whether an Agreement should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge and the other Parties consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

For all but two of the Parties, this Agreement is comprehensive in that it resolves all rate-making and other issues raised in this proceeding. Two Parties – GEC and Pollution Probe – oppose the treatment of customer additions under incentive regulation which is one component of the settlement of Issue 5.1 ("Y Factors").

The Parties who are shown as accepting and agreeing with and/or taking no position on the settlement of the issues in this Agreement (the "Agreeing Parties") have settled the issues as a package ("Package"). For greater certainty, the Agreeing Parties do not include the Parties who oppose the settlement of any issue or part thereof (i.e., GEC and Pollution Probe).

The Agreeing Parties agree that none of the parts of the Package are severable, with the exception of the one component of the settlement of Issue 5.1 that is opposed by GEC and Pollution Probe. If the Board rejects one or more components of the Package (other than the Issue 5.1 component that is opposed by GEC and Pollution Probe), then there is no Agreement unless and until the Agreeing Parties further agree to accept the Board's decisions in this regard, without changing the disposition of any of the other components of the Package.

None of the Parties can withdraw from the Agreement except in accordance with Rule 32 of the Rules. Unless stated otherwise, the settlement of any particular issue in this proceeding is entirely without prejudice to the rights of Parties to raise the same issue in any other proceedings.

The Parties agree that any and all (i) information, documents and electronic data, including computer software and/or models (collectively, the “Confidential Documents”); and (ii) positions, negotiations and discussions of any kind whatsoever (collectively, the “Confidential Discussions”), which were, respectively, (i) produced or exchanged; or (ii) advanced or conducted during and in furtherance of the Settlement Conference, shall remain strictly confidential.

The Parties expressly acknowledge, covenant and represent to one another that each of the Parties and their agents, including without limitation, lawyers and external experts, are under a continuing duty of confidentiality to one another, under the laws of Ontario, not to use, for any reason whatsoever, any Confidential Document or any information obtained from, during or as a consequence of the Confidential Discussions for any purpose. Each of the Intervenor Parties further covenants to return forthwith to the Company all copies, including electronic copies, of the financial model (the “Model”) produced by the Company during the course of the Settlement Conference to such intervenor Parties or their agents, including solicitors and external experts, and to forthwith provide written confirmation that, to the best of their knowledge, no electronic or other copies of the Model, have been retained. The prohibitions set forth in this paragraph shall be strictly enforced, unless the Company has expressly waived its rights by having agreed in writing to the inclusion of any Confidential Document in this Settlement Agreement, in the form originally provided by the Company to the other Parties.

VI. OVERVIEW OF AGREEMENT

The Board stated in its Natural Gas Forum Report that rate regulation should meet three objectives:

1. establish incentives for sustainable efficiency improvements that benefit customers and shareholders;
2. ensure appropriate quality of service for customers; and
3. create an environment that is conducive to investment, to the benefit of customers and shareholders.

Those Parties shown as being in agreement with the resolution of the various issues in this proceeding accept that the five-year IR Plan established in this Agreement meets these objectives. Further, these Parties have agreed to minimize reliance on Y and Z factors and off-ramps. The Parties also agree that this IR Plan is expected to put downward pressure on the Company's rates by encouraging new levels of efficiency and provide the regulatory stability needed for anticipated investment in Ontario. The IR Plan agreed to is intended by the Parties to ensure that the benefits of new efficiencies will be shared with customers during the term of the IR Plan.

Those Parties shown as being in agreement with the resolution of the various issues in this proceeding represent all but two stakeholders and constituencies with an interest in Enbridge's rates. The Agreeing parties represent a wide range of sometimes competing interests who hold a wide range of sometimes competing objectives.

VII. ISSUE-BY-ISSUE SETTLEMENTS

1 MULTI-YEAR INCENTIVE RATEMAKING FRAMEWORK

1.1 What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

- **Complete Settlement:** Subject to the agreement on Issue 9.1, the Parties agree that a revenue per customer cap framework, as further delineated in this Agreement, is appropriate for Enbridge for the period 2008 to 2012. Accordingly, the Parties agree that it is unnecessary to pursue this issue further in this proceeding.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, SEC, Timmins and Transalta.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-4-1	Y Factor – Capital
B-4-2	Y Factors – Other
B-5-1	Deferral and Variance Accounts
B-6-1	Rate Filing Process and Report Requirements
D-3- 1	PEG Report June 20, 2007
I-1-1 to 4	Board Staff Interrogatories 1 to 4
I-3-1 to 2	CCC Interrogatories 1 to 2
I-5-1	Energy Probe Interrogatory 1
I-6-1	GEC Interrogatory 1
I-11-1 to 2	OAPPA Interrogatories 1 to 2
I-11-1 to 4	SEC Interrogatories 1 to 4
I-16-1	TransAlta Interrogatory 1
I-17-3 to 4, 7 to 9, 11, 19, 25	IGUA Interrogatories 3 to 4, 7 to 9, 11, 19, and 25

JTA.54	Board Staff Undertaking 54 to EGD
JTB.4	IGUA Undertaking 4 to EGD
JTB.12 and 25	SEC Undertakings 12 and 25 to EGD
JTB.42	IGUA Undertakings JTB.42 to PEG
JTB.47	IGUA Undertaking JTB.47 to Board Staff
JTC.1	PWU Undertaking JTC.1 to PEG
L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-4-1	PWU Evidence of Dr. Cronin
L-5-1	IGUA Evidence
L-I-1-1	Board/PEG November 14 Response to Union

1.2 What is the method for incentive regulation that the Board should approve for each utility?

- **Complete Settlement:** The Parties agree that the Company's distribution revenue, in each year of the period January 1, 2008 through December 31, 2012 (the "Term"), shall be determined by the application of the Distribution Revenue Requirement per Customer Formula ("Adjustment Formula") as follows:

Adjustment Formula	$DRR_t = \left(\frac{DRR_{t-1} - (Y_{t-1} + Z_{t-1})}{C_{t-1}}\right) * (1 + P * INF) * C_t + Y_t + Z_t$

Where:

DRR	=	the distribution revenue requirement
t	=	the rate year
C	=	the average number of customers
P	=	the inflation coefficient
INF	=	the inflation index
Y	=	pass throughs at cost of service
Z	=	exogenous factors

The Parties agree that the application of the Adjustment Formula, for 2008, as set out in Appendix C is consistent with this Agreement.

- **Participating Parties:** All Parties participated in negotiation and settlement of this issue except Coral/Shell Energy.

- **Approval:** All participating Parties accept and agree with the settlement except the following Parties take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, SEC, Timmins and Transalta.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1- 1	Incentive Regulation Proposal
B-5-1	Deferral and Variance Accounts
B-6-1	Rate Filing Process and Report Requirements
D-3- 1	PEG Report June 20, 2007
I-3-3 to 9	CCC Interrogatories 3 to 9
I-11-5 to 21	SEC Interrogatories 5 to 21
I-13-1 to 2	VECC interrogatories 1 to 2
I-17-1 to 2, 10, 12, 26 to 28, 30	IGUA Interrogatories 1 to 2, 10, 12, 26 to 28, and 30
JTB.2 and 5	IGUA Undertakings 2 and 5 to EGD
JTB.25	SEC Undertaking 25 to EGD
JTB.42,and 43	IGUA Undertakings JTB.42 and 43 to PEG
JTB.46 and 47	IGUA Undertakings JTB.46 and 47 to Board Staff
L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-4-1	PWU Evidence of Dr. Cronin

1.3 Should weather risk continue to be borne by the shareholders, and if so what other adjustments should be made?

- **Complete Settlement:** The Parties agree that no change needs to be made to the attribution of weather risk during the term of the IR Plan.

- **Participating Parties:** All Parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-5-1	Deferral and Variance Accounts
I-1-5	Board Staff Interrogatory 5
I-3-10	CCC Interrogatory 10
I-11-22 to 25	SEC Interrogatory 22 to 25
I-13-3	VECC Interrogatory 3
JTB.33	VECC Undertaking 33 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-2-1	CCC/VECC Evidence of Dr. Booth
L-I-1-1	Board/PEG November 14 Response to Union

2 INFLATION FACTOR

2.1 What type of index should be used as the inflation factor (industry specific index or macroeconomic index)?

2.1.1 Which macroeconomic or industry specific index should be used?

- **Complete Settlement:** The Parties agree that the inflation index to be used in any adjustment formula that is adopted for Enbridge, by the Board in this proceeding, is the actual year-over-year change in the annualized average of four quarters (using Q2 to Q2) of Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP IPI FDD"). For 2008, the inflation index calculated in this manner is 2.04%. The inflation index will be adjusted annually on this basis, as set out in Issue 12.1 below, with no true-ups.

- **Participating Parties:** All Parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals**: All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-2-1	Inflation index
I-3-11	CCC Interrogatory 11
I-7-3	LPMA Interrogatory 3
JTA.65	BOMA/LPMA/WPSPGA Undertaking 65 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-4-1	PWU Evidence of Dr. Cronin

2.2 Should the inflation factor be based on an actual or forecast?

- **Complete Settlement:** See the settlement of Issues 2.1 and 2.1.1 above.

2.3 How often should the Board update the inflation factor?

- **Complete Settlement:** See the settlement of Issues 2.1 and 2.1.1 above.

2.4 Should the gas utilities ROE be adjusted in each year of the incentive regulation (IR) plan using the Board's approved ROE guidelines?

- **Complete Settlement:** The Parties agree that, except as otherwise provided in this Agreement, the percentage rate of return on equity ("ROE") of 8.39% that is already included in the Company's rates for 2007 will not be adjusted under the Board's formula for setting the ROE ("ROE Formula") during the term of the IR Plan.

- **Participating Parties:** All Parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-2-1	Inflation index
B-6-1	Rate Filing Process and Report Requirements
I-3-12 to 13	CCC Interrogatories 12 to 13
I-7-19	BOMA/LPMA/WGSPG Interrogatory 19
I-13-4	VECC Interrogatory 4
JTB.42	IGUA Undertaking JTB.42 to PEG
L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-2-1	CCC/VECC Evidence of Dr. Booth
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-4-1	PWU Evidence of Dr. Cronin
L-5-1	IGUA Evidence

3 X Factor

3.1 How should the X factor be determined?

- **Complete Settlement:** The evidence in the proceeding dealt with a number of complex issues, including the productivity or X factor. Evidence on this issue was filed by five experts, most of whom did not share the views or conclusions of the others. There were also differences among the positions advanced by many of the Parties and some Parties took no position at all on this issue.

  The Parties were unable to agree on the appropriate X factor for inclusion in Enbridge's revenue per customer cap IR framework. As an alternative to an X factor, the Parties agreed on an inflation coefficient, the effect of which is to adjust annual distribution revenues by a percentage of the annual rate of inflation (by multiplying the annual rate of inflation by the inflation coefficient). IR plans adopted in other jurisdiction have also expressed the X factor as a percentage of inflation. The Parties agree that the inclusion of the inflation coefficient in the Adjustment Formula is in lieu of the inclusion of an "X factor" and/or a "stretch factor".

The Parties agree that the value of the inflation coefficient will vary over the term of the IR Plan. The Parties note that IR Plans in other jurisdictions have adopted X factors that also vary from year to year over the term of the IR plan. The Parties agree, that for each year of the IR Plan, the Inflation Coefficient shall be as follows:

Year	Inflation Coefficient ("P")
2008	0.60
2009	0.55
2010	0.55
2011	0.50
2012	0.45

The X factors implicit in the agreement with respect to the value of the Inflation Coefficient are as follows:

Year	Implied X Factor (“X”) (as a % of GDP IPI FDD)
2008	40
2009	45
2010	45
2011	50
2012	55

At a GDP IPI FDD of 2.04% in each of the years 2008 to 2012 inclusive, the X factor implicit in the agreement of the Parties is 0.816% in 2008, 0.918% in 2009 and 2010, 1.02% in 2011 and 1.12% in 2012.

These X factors fall within the range which the expert evidence, as a whole, supports. The Parties recognize that, at 2.04% Inflation, these X factor values fall below the revenue per customer cap X factor Dr. Lowry estimates for Enbridge of 2.08% and below the X factor recommendation of Dr. Loube of 100% of inflation, but above the X factor value recommended by Enbridge’s experts, Dr. Carpenter and Dr. Bernstein, of - 0.14%. Moreover, compared to an X factor which is fixed for the duration of the IR Plan, expressing the X factor in each year as a percentage of inflation has advantages for ratepayers in the event inflation, in future years, exceeds 2.04%. For example, at 4% inflation, the X factor implicit in the agreement of the Parties is 1.60% in 2008, 1.80% in 2009 and 2010, 2.0% in 2011 and 2.2% in 2012.

In all of these circumstances, the Parties agreeing to the resolution of this issue preferred to compromise their differences rather than expose themselves to the risks associated with litigating this complex issue.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, SEC and Timmins.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
I-1-7 and 29 to 57	Board Staff Interrogatories 7 and 29 to 57
I-3-14 to 15	CCC Interrogatories 14 to 15
I-7-4 and 6	LPMA Interrogatories 4 and 6
I-11-26 to 32	SEC Interrogatories 26 to 32
I-13-5 to 13	VECC Interrogatories 5 to 13
I-14-1 to 11	VECC and CCC Interrogatories 1 to 11
I-17-14 to 18, 20 to 21, 29	IGUA interrogatories 14 to 18, 20 to 21, 29
JTA.58	VECC Undertaking 58 to EGD (Brattle Group)
JTA.60 to 63	VECC Undertakings 60 to 63 to EGD (Brattle Group)
JTB.8 to 10	SEC Undertakings 8 to 10 to EGD
JTB 27 to 32	Board Staff Undertakings 27 to 32 to EGD (Brattle Group)
JTB 34 and 35	CCC Undertakings 34 and 35 to PEG (Dr. Lowry)
JTB.37 to 39	CCC/VECC Undertakings JTB.37 to 39 to PEG
JTB.42 and 44	IGUA Undertakings JTB.42 and 44 to PEG
JTC.1 and 2	Power Workers Union Undertakings JTC.1 and 2 to PEG
JTC.3 and 4	SEC Undertakings JTC.3 and 4 to PEG
JTC.5 to 18	Enbridge Undertakings JTC.5 to 18 to PEG
JTD.1 and 2	Board Staff Undertakings 1 and 2 to CCC/VECC (Dr. Loube)
JTD.3 to 7	IGUA Undertakings 3 to 7 to CCC/VECC (Dr. Loube)
JTE.1 to 12	Board Staff Undertakings 1 to 12 to PWU (Dr. Cronin)
JTE.13 to 18	IGUA Undertakings 13 to 18 to PWU (Dr. Cronin)
JTE.19 to 22	SEC Undertakings 19 to 22 to PWU (Dr. Cronin)
JTE.23	VECC Undertaking 23 to PWU (Dr. Cronin)
JTE.24 to 26	Union Undertakings 24 to 26 to PWU (Dr. Cronin)
JTF.1 to 10	EGD Undertakings 1 to 10 to Board Staff (Dr. Lowry - PEG)
JTF.11 and 12	PWU Undertakings 11 and 12 to Board Staff (Dr. Lowry – PEG)
JTF 13 and 14	BOMA/LPMA/WGSPG Undertakings 13 and 14 to Board Staff (Dr. Lowry – PEG)
JTF.15	CCC Undertaking 15 to Board Staff (Dr. Lowry – PEG)
JTF.16	EGD Undertaking 16 to Board Staff (Dr. Lowry – PEG)
JTF.17	CCC Undertaking to EGD (Brattle Group)
JTF.18	LPMA Undertaking 18 to EGD (Brattle Group)

JTF.19	BOMA/LPMA/WGSPG Undertaking 19 to EGD (Brattle Group)
JTF.20	IGUA Undertaking 20 to EGD (Brattle Group)
JTF.21 to 25	Board Staff Undertakings 21 to 25 to EGD (Brattle Group)
JTF.26 to 28	Board Staff (Dr. Lowry – PEG) Undertakings 26 to 28 to EGD (Brattle Group)
L-1-1	Rate Adjustment Indexes of Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-3-2	CCC/VECC/City of Kitchener Supplemental Evidence of Dr. Loube
L-4-1	PWU Evidence of Dr. Cronin
L-5-1	IGUA Evidence
L-I-1-1	Board/PEG November 14 Response to Union

3.2 What are the appropriate components of an X factor?

- **Complete Settlement:** See the settlement of Issue 3.1 above

B-1-1	Incentive Regulation Proposal
I-7-5	LPMA Interrogatory 5
I-11-33 to 36	SEC Interrogatory 33 to 36
I-14-12 to 15	VECC and CCC Interrogatory 12 to 15
JTA.59	VECC Undertaking 59 to EGD (Brattle Group)
JTB.11 and 13	SEC Undertakings 11 and 13 to EGD
JTB 34 and 35	CCC Undertakings 34 and 35 to Board Staff (Dr. Lowry)
JTB.40 and 41	BOMA-LPMA-WGSPG Undertakings JTB.40 and 41 to PEG
JTB.42 and 44	IGUA Undertakings JTB.42 and 44 to PEG
JTC.1 and 2	Power Workers Union Undertakings JTC.1 and 2 to PEG
JTC.3 and 4	SEC Undertakings JTC.3 and 4 to PEG
JTC.5 to 18	Enbridge Undertakings JTC.5 to 18 to PEG
L-1-1	Rate Adjustment Indexes of Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-3-2	CCC/VECC/City of Kitchener Supplemental Evidence of Dr. Loube
L-4-1	PWU Evidence of Dr. Cronin
L-5-1	IGUA Evidence
L-I-1-1	Board/PEG November 14 Response to Union

3.3 What are the expected cost and revenue changes during the IR plan that should be taken into account in determining an appropriate X factor?

- **Complete Settlement:** See the settlement of Issue 3.1 above
- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B, Tab 4, Schedule 1	Y-Factor – Capital
I-1-8 to 11, 37 to 46	SEC Interrogatory 8 to 11, 37 to 46
JTB 14 to 16	SEC Undertakings 14 to 16 to EGD

JTB.42 and 44	IGUA Undertakings JTB.42 and 44 to PEG
JTC.1 and 2	Power Workers Union Undertakings JTC.1 and 2 to PEG
JTC.3 and 4	SEC Undertakings JTC.3 and 4 to PEG
JTC.5 to 18	Enbridge Undertakings JTC.5 to 18 to PEG
L-1-1	Rate Adjustment Indexes of Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-3-2	CCC/VECC/City of Kitchener Supplemental Evidence of Dr. Loube
L-4-1	PWU Evidence of Dr. Cronin
L-5-1	IGUA Evidence
L-I-1-1	Board/PEG November 14 Response to Union

4 AVERAGE USE FACTOR

4.1 Is it appropriate to include the impact of changes in average use in the annual adjustment?

- **Complete Settlement:** The Parties agree that the revenue per customer cap methodology incorporates the forecast impact of changes in average use on an annual forecast basis.

  The Parties also agree to establish a variance account (the "Average Use True-Up Variance Account" or "AUTUVA") in which to "true-up" the difference in the revenue impact, exclusive of gas costs, between the forecast of average use per customer for general service rate classes (Rate 1 and Rate 6) that is embedded in the volume forecast that underpins Rates 1 and 6 (the "Forecast AU") and the weather normalized average use experienced in each year of the IR Plan (the "Normalized AU"). The Parties agree that the AUTUVA will operate for the term of the IR Plan.

  Further, the Parties agree that with respect to the AUTUVA:

  (i) the calculation of the volume variance impact due to the difference between the Forecast AU and the Normalized AU shall exclude the volumetric impact of Demand Side Management ("DSM") programs in that year;

  (ii) the revenue impact of the difference between Forecast AU and the Normalized AU shall be calculated using a unit rate determined in the same manner as determined for the purpose of the Lost Revenue Adjustment Mechanism ("LRAM"), extended by the difference in average use per customer and the number of customers (filed at Exhibit C-2-1, Appendix A, page 1) as agreed herein; and

(iii) the revenue impacts of all differences between Forecast AU and Normalized AU (negative or positive) shall be recorded in the AUTUVA; i.e., the AUTUVA shall be symmetrical.

For the purpose of determining 2008 rates, the Parties accept the volumetric average use per customer forecast for each rate class that is set out in Exhibit C-2-1, Appendix A, page 20, as follows:

Rate Class	**Forecast average use** (m^3)
Rate 1 – Residential	2,647
Rate 6	24,204

The Parties acknowledge that the annual forecast and true up of the impacts of changes in average use will be confined to Rates 1 and 6, throughout the term of the IR Plan, and will have no effect on the rates of other rate classes.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.
- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, SEC, Timmins and Transalta.
- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-5-1	Deferral and Variance Accounts
B-6-1	Rate Filing Process and Report Requirements
D-4- 1	CGA Report on Declining Average Use
I-3-16 to 17	CCC Interrogatories 16 to 17
I-11-47 to 53	SEC Interrogatories 47 to 53
I-13-14	VECC Interrogatory 14
I-17-5 and 13	IGUA Interrogatory 5 and 13
JTA. 67	BOMA/LPMA/WPSPGA Undertaking 67 to EGD
JTB.18	SEC Undertaking 18 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-5-1	IGUA Evidence

4.2 How should the impact of changes in average use be calculated?

- **Complete Settlement:** See the settlement of Issue 4.1 above.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
I-1-12 to 14	Board Staff Interrogatories 12 to 14
I-3-18-19	CCC Interrogatories 18 to 19
I-6-2	IGUA Interrogatory 2
JTB.19	SEC Undertaking 19 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-5-1	IGUA Evidence

4.3 If so, how should the impact of changes in average use be applied (e.g., to all customer rate classes equally, should it be differentiated by customer rate classes or some other manner)?

- **Complete Settlement:** See the settlement of Issue 4.1 above.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-4- 1	Y Factor – Capital
B-4-2	Y Factor - Other
B-5-1	Deferral and Variance Accounts
B-6- 1	Rate Filing Process and Report Requirements
I-1-15 to 19	Board Staff Interrogatories 15 to 19
I-3-20 to 28	CCC Interrogatories 20 to 28
I-5-2 to 3	Energy Probe Interrogatories 2 to 3
I-6-3	GEC Interrogatories 3
I-7-8 to 14	LMPA Interrogatories 8 to 14
I-9 1 to 3	Pollution Probe Interrogatories 1 to 3
I-11-54 to 59	SEC Interrogatories 54 to 59
I-13-15	VECC Interrogatory 15
I-17-22 to 24	IGUA Interrogatories 22 to 24
JTA 53	Board Staff Undertaking 53 to EGD
JTA 66	BOMA/LPMA/WPSPGA Undertaking 66 to EGD
JTA.1 and 2	Pollution Probe Undertakings 1 and 2 to EGD
JTB.2	IGUA Undertaking 2 to EGD
JTB.20 to 22	SEC Undertakings 20 to 22 to EGD
JTB.42 to 44	IGUA Undertakings JTB.42 to 44 to PEG

5 Y FACTOR

5.1 What are the Y factors that should be included in the IR plan?

- **Incomplete Settlement:** The Parties agree that in each year of the IR Plan, the following non-capital cost items shall be treated as Y factors:

  (i) DSM program costs which were approved by the Board in the EB-2006-0021 proceeding for the years 2007 through 2009;

(ii) CIS/customer care costs resulting from the "true up" process approved by the Board for the Customer Care EB-2006-0034 Settlement Agreement;

(iii) upstream gas costs;

(iv) upstream transportation, storage and supply mix costs; and

(v) changes in the embedded carrying cost of gas in storage and working cash related to changes to gas costs.

The Parties agree that the incremental revenue requirement impacts associated with annual capital expenditures related to the attachments of natural gas-fired power generation projects, that have been approved by the Board pursuant to "leave to construct" applications and placed into service, shall be treated as Y factors. The Parties' agreement in this regard is not intended to and shall not limit the positions that any of the Parties may take in support of or in opposition to such "leave to construct" applications. The Parties further agree that the incremental revenue impacts associated with annual capital expenditures related to system reinforcement shall not be treated as Y factors with the exception of the incremental revenue requirement impacts that are wholly related to system reinforcement necessitated by the attachment of the natural gas-fired power generation projects referred to above. These system reinforcement costs are identified as part of the "project costs" in the "leave to construct" applications for new natural gas-fired power generation customers. These project costs will be allocated in accordance with the latest Board-approved cost allocation methodologies and rate design principles as currently illustrated at Appendix E.

All Parties, except GEC and Pollution Probe, also agree that there should not be a Y factor related to the incremental revenue requirement impact of other types of customer attachments during the term of the IR Plan.

The Parties agree that the incremental revenue impact associated with the Y factors will not be adjusted by the Adjustment Formula but will be passed through to rates and allocated to rate classes in accordance with the latest Board-approved cost allocation methodology and rate design principles, determined based on system-wide information.

The Parties agree that Enbridge shall establish the following new deferral and variance accounts for the term of the IR Plan:

(i) pursuant to the settlement of issue 4.1, a Average Use True-Up Variance Account ("AUTUVA");

(ii) pursuant to the settlement of issue 6.1, a Tax Rate and Rule Change Variance Account ("TRRCVA"); and

(iii) pursuant to the settlement of issues 10.1 and 10.2, an Earnings Sharing Mechanism Deferral Account ("ESMDA").

The Parties agree that Enbridge shall maintain the deferral and variance accounts listed in Appendix B to this Agreement, for the term of the IR Plan. The Parties also agree that, pursuant to the settlement of Issue 14.1, the 2008 "OHCVA" threshold forecast amount for variance determination purposes shall be reduced by $3 million, to $5.84 million.

The Parties agree that clearance of Board-approved balances in the deferral and variance accounts will occur in conjunction with each following fiscal year's July 1st QRAM proceeding. The Parties also agree that if the clearance of balances in the deferral and variance accounts established prior to 2008 (which accounts are listed in Appendix H) is approved by the Board by May 15, 2008, such clearance will occur in conjunction with the July 1st, 2008 QRAM. This would include clearance of any approved 2005 and 2006 DSM, LRAM and Shared Savings Mechanism variance accounts at July 1, 2008 unless specified differently by a Board decision in the EB-2007-0893 DSM-related proceeding. With respect to amounts which do not receive approval for clearance by May 15, 2008, the Company will bring forward requests for review and approval as quickly as circumstances permit.

The Parties agree that deferral and variance balances will be allocated to rate classes in accordance with existing Board approved cost allocation methodology and rate design principles.

- **Participating Parties:** All Parties participated in the negotiation settlement and discussions of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree all aspects of the settlement except:

(i) GEC and Pollution Probe who agree with giving Y factor treatment to DSM program costs and the incremental revenue requirement impacts of Board-approved power generation attachments, oppose the agreement that there should not be a Y factor related to all other customer attachments and take no position on giving Y factor treatment to other costs; GEC will be advancing a proposal for a customer attachment incentive;

(ii) SEC who agrees with the settlement of all components of this issue with the exception of the agreement regarding the AUTUVA and the TRRCVA, with respect to which SEC takes no position; and

(iii) the following Parties who take no position on any part of this issue: Kitchener, PWU and Timmins.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-4- 1	Y Factor – Capital
B-4-2	Y Factor - Other
B-5-1	Deferral and Variance Accounts
B-6- 1	Rate Filing Process and Report Requirements
I-1-15 to 19	Board Staff Interrogatories 15 to 19
I-3-20 to 28	CCC Interrogatories 20 to 28
I-5-2 to 3	Energy Probe Interrogatories 2 to 3
I-6-3	GEC Interrogatories 3
I-7-8 to 14	LMPA Interrogatories 8 to 14
I-8-3	OAPPA Interrogatory 3
I-9 1 to 3	Pollution Probe Interrogatories 1 to 3
I-11-54 to 59	SEC Interrogatories 54 to 59
I-13-15	VECC Interrogatory 15
I-17-22 to 24	IGUA Interrogatories 22 to 24
JTA 53	Board Staff Undertaking 53 to EGD
JTA.1 and 2	Pollution Probe Undertakings 1 and 2 to EGD
JTA 66	BOMA/LPMA/WPSPGA Undertaking 66 to EGD
JTB.2	IGUA Undertaking 2 to EGD
JTB.20 to 22	SEC Undertakings 20 to 22 to EGD
JTB.42 to 44	IGUA Undertakings JTB.42 to 44 to PEG
L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-3	CCC/VECC/City of Kitchener – Dr. Loube
L-5-1	IGUA Evidence

5.2 What are the criteria for disposition?

- **Complete Settlement:** The Parties agree that the disposition of Y factors as per issues 5.1 above shall be in accordance with existing Board-approved cost allocation and rate design principles.

- **Participating Parties:** All Parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU and Timmins.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-4- 1	Y Factor – Capital
B-4-2	Y Factor – Other
I-6-4	GEC Interrogatory 4
I-7-15 to 16	LPMA Interrogatories 15 to 16
JTB.42	IGUA Undertaking JTB.42 to PEG

L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-5-1	IGUA Evidence

6 Z FACTOR

6.1 What are the criteria for establishing Z factors that should be included in the IR plan?

- **Complete Settlement:**

Z-Factor Criteria

The Parties agree that Z factors generally have to meet the following criteria:

(i) the event must be causally related to an increase/decrease in cost;

(ii) the cost must be beyond the control of the Company's management and is not a risk in respect of which a prudent utility would take risk mitigation steps;

(iii) the cost increase/decrease must not otherwise reflected in the per customer revenue cap;

(iv) any cost increase must be prudently incurred; and

(v) the cost increase/decrease must meet the materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event).

ROE Methodology

If a proceeding is instituted before the Board, before the term of this IR Plan expires, in which changes to the methodology for determining the ROE is requested, then all Parties, including Enbridge, will be free to take such positions as they consider appropriate with respect to that proceeding. Enbridge may apply to the Board to institute such a proceeding should a change in the methodology for determining return on equity be approved or adopted by the Board. If the Board determines that a change in methodology is appropriate, Enbridge or any other Party in this proceeding, may apply for determination of whether or not that change should be applied to Enbridge during the term of the IR Plan. All Parties, including Enbridge, would be free to take any position on that application, including without limitation:

(i) opposing the application of the change in methodology to Enbridge during the IR Plan;

(ii) proposing offsetting or complimentary adjustments to Enbridge's IR Plan, revenue or rates that the Party considers appropriate to the circumstances; and

(iii) taking any other positions as the Party may consider relevant and the Board agrees to hear.

If, after hearing such application, the Board determines that such methodology change should be treated as a Z factor, the Parties agree that such decision will operate on a prospective basis only.

NGEIR

The Parties agree that any rate impacts specifically identified in any order of the Board related to certain intervenors' petitions to the Lieutenant Governor in Council in connection with the Board's NGEIR Decision (EB-2006-0551) or related to the Board's disposition of Enbridge's pending natural gas storage allocation proceeding (EB-2007-724-725) will be treated as Z factors, subject to the materiality threshold.

Changes in Tax Rules and Rates

With respect to changes in the annual amount of forecast taxes for Enbridge that result from future changes to federal and/or provincial legislation and/or regulations thereunder (including changes in federal tax rates and calculation rules announced in March and October of 2007), the Parties agree as follows:

(i) amounts calculated in association with expected tax rate and rule changes with respect to corporate income tax rates, provincial capital tax rates and capital cost allowance ("CCA") rates that occur within the term of the IR plan, based upon the 2007 Board Approved base level benchmarks embedded in rates, will be shared equally between ratepayers and the Company; Appendix D is a schedule that shows the estimated impact of expected changes in tax rates for the period 2008-2012; the 50% share that is for the account of ratepayers, pursuant to the settlement of this issue, is shown at line 45; Appendix C includes a schedule that sets out the estimated distribution revenue impacts for the years 2008-2012; the same tax impact that is shown at line 45 of Appendix D is also shown at line 10 of the schedule included in Appendix C;

(ii) associated with the sharing described above is a true-up variance account mechanism (the Tax Rate and Rule Change Variance Account or "TRRCVA") relating to changes in actual rates and rules which are different from those proposed and embedded in rates; in the event that the future tax rates and rules are not as currently expected, the Company will calculate the appropriate amounts which should be shared between ratepayers and the Company and record the appropriate variance in the variance account to be returned to or collected from ratepayers; this true-up will occur annually, along with any associated required change to ongoing future rates; and

(iii) the settlement of this issue does not prejudice and is in no way determinative of the position that parties may wish to take on this issue in other proceedings; moreover, the settlement of this issue is not intended to be an expression of the principles and rules that should govern the Board's disposition of this issue outside the framework of this Agreement.

The Parties, who are in agreement with the settlement of this issue, have compromised their individual views with respect to the extent which the impact of changes in federal tax rates and calculation rules are properly characterized as a Z factor. These compromises have been in order to reach an agreement on this issue.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except:

  (i) SEC who agrees with the settlement except for the settlement of the tax change issue, on which it takes no position; and

  (ii) the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-5-1	Deferral and Variance Accounts
I-1-20	Board Staff Interrogatory 20
I-3-29 to 32	CCC Interrogatory 29 to 32
I-7-1 and 17	LPMA Interrogatories 1 and 17
I-11-60 to 61	SEC Interrogatories 60 to 61

JTB.23	SEC Undertaking 23 to EGD
JTB.42 and 43	IGUA Undertakings JTB.42 and 43 to PEG
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-5-1	IGUA Evidence

6.2 Should there be materiality tests, and if so, what should they be?

- **Complete Settlement:** See Issue 6.1
- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
I-7-2	LPMA Interrogatory 2
JTB.2	IGUA Undertaking 2 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-5-1	IGUA Evidence

7 NATURAL GAS ELECTRICITY INTERFACE REVIEW (NGEIR) DECISIONS

7.1 How should the impacts of the NGEIR decisions, if any, be reflected in rates during the IR plan?

- **Complete Settlement:** The Parties agree, subject to the reservations of rights described in the settlement of 6.1 of this Agreement, that Enbridge will implement the Board's final NGEIR decisions, where relevant and applicable, in accordance with any Board direction in this regard and in accordance with existing Board-approved cost allocation and rate design principles.
- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.
- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.
- **Evidence:** The evidence in support of the settlement of this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-4- 1	Y Factor – Capital
B-4-2	Y Factor – Other
B-6- 1	Rate Filing Process and Report Requirements
I-11-62	SEC Interrogatory 62
I-16-2 to 4	TransAlta Interrogatories 2 to 4

8 TERM OF THE PLAN

8.1 What is the appropriate plan term for each utility?

- **Complete Settlement:** The Parties agree, subject to the settlement of Issue 9.1 below, that the term of the Company's IR Plan shall be five years; namely calendar years 2008 to 2012 inclusive.

  The Parties also agree that a consultation between Enbridge and the Parties may be convened, at the request of the Company, in year four of the term of the IR Plan and as soon as possible after the 2010 year-end results become available, in order to discuss and consider whether an extension of the IR Plan for up to two years (i.e., to 2014) is warranted.

- **Participating Parties:** All Parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.

- **Evidence:** The evidence in support of the settlement of this issue includes the following:

B-1-1	Incentive Regulation Proposal
I-3-33	CCC Interrogatory
I-7-7	LPMA Interrogatory 7
I-11-63 to 64	SEC Interrogatories 63 to 64
I-13-16	VECC Interrogatory 16
JTB.42	IGUA Undertaking JTB.42 to PEG
L-5-1	IGUA Evidence

9 OFF-RAMPS

9.1 Should an off-ramp be included in the IR plan?

- **Complete Settlement:** The Parties agree that if, in any year of the IR Plan, there is a 300 basis point or greater variance in weather normalized utility earnings, above or below the amount calculated annually by the application of the ROE Formula, Enbridge shall file an application with the Board, with appropriate supporting evidence, for a review of the Adjustment Formula. The Parties agree that this review will be prospective only (i.e., will not result in any confiscation of earnings). During the course of that review, the Board may be asked to determine whether the application of the IR Plan, including the Adjustment Formula, should continue and, if so, with or without modifications. All Parties, including Enbridge, shall be free to take such positions as they consider appropriate with respect to that application, including, without limitation:

(i) proposing that any component of the Adjustment Formula, including the value of the inflation coefficient, should be changed;

(ii) proposing that the IR Plan be terminated; and

(iii) taking any other positions as the Party may consider relevant and the Board agrees to hear.

Enbridge shall file such application as soon as is reasonably possible in the year following the year in which the over or under earnings threshold is met or exceeded, unless all of the Parties to this Agreement agree otherwise at that time.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.
- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.
- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
I-1-21	Board Staff Interrogatory 21
I-1-65 & 66	SEC Interrogatories 65 & 66
JTB.42	IGUA Undertaking JTB.42 to PEG
L-4-1	PWU Evidence of Dr. Cronin
L-5-1	IGUA Evidence

9.2 If so, what should be the parameters?

- **Complete Settlement:** See the settlement of Issue 9.1 above

10 Earning Sharing Mechanism (ESM)

10.1 Should an ESM be included in the IR plan?

- **Complete Settlement:** The Parties agree that the IR Plan shall include an earnings sharing mechanism ("ESM") that shall be used to calculate an earning sharing amount, as follows:

(i) if in any calendar year, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than 100 basis points over the amount calculated annually by the application of the Board's ROE Formula in any year of the IR Plan, then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge and its ratepayers;

(ii) for the purpose of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings;

(iii) all revenues that would otherwise be included in revenue in a cost of service application shall be included in revenues in the calculation of the earnings calculation and only those expenses (whether operating or capital) that would be otherwise allowable as deductions from earnings in a cost of service application, shall be included in the earnings calculation.

The Parties acknowledge that the following shareholder incentives and other amounts are outside the ambit of the ESM:

(i) amounts in respect of the application of the Shared Savings Mechanism ("SSM") and the LRAM;

(ii) amounts related to storage and transportation related deferral accounts; and

(iii) the Company's 50% share of the tax amount calculated in association with expected tax rate and rule changes as per the settlement of Issue 6.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals**: All participating Parties accept and agree with the settlement except:

(i) the following Parties who take no position on the issue: Kitchener, PWU, Timmins, and Transalta;

(ii) GEC and Pollution Probe who take no position on the settlement of this issue except that they agree that SSM and LRAM amounts are outside the ambit of the ESM; and

(iii) SEC who agrees with the settlement of this issue except that it takes no position on the agreement to exclude the Company's share of the tax amount resulting from expected tax rate and rule changes, from the ESM.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1- 1	Incentive Regulation Proposal
D-5-1	Econalysis Survey of PBR Mechanisms
I-1-22	Board Staff Interrogatory 22
I-1-34	CCC Interrogatory 34
I-7-21	LPMA Interrogatory 21
I-11-67	SEC Interrogatory 67
I-13-17	VECC Interrogatory 17
JTB.3	IGUA Undertaking 3 to EGD
JTB.6 and 7	TransAlta Undertakings 6 and 7 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-3-2	CCC/VECC/City of Kitchener Supplemental Evidence of Dr. Loube
L-4-1	PWU Evidence of Dr. Cronin
L-5-1	IGUA Evidence

10.2 If so, what should be the parameters?

- **Complete Settlement:** See the settlement of Issue 10.1 above

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
JTB.2	IGUA Undertaking 2 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-5-1	IGUA Evidence

11 REPORTING REQUIREMENTS

11.1 What information should the Board consider and stakeholders be provided with during the IR plan?

- **Complete Settlement:** Enbridge agrees to support making its RRR filings with the Board available to intervenors. It also agrees to prepare and provide the following utility information, annually, for the most recent historical year (the exhibit numbers noted below are from the Company's 2007 Rate Case (EB-2006-0034)):

  (i) calculation of revenue deficiency/ (sufficiency) (Exh. F5-1-1);

  (ii) statement of utility income (Exh. F5-1-2);

  (iii) statement of earnings before interest and taxes (Exh. F5-1-2);

  (iv) summary of cost of capital (Exh. E5-1-1);

  (v) total weather normalized throughput volume by service type and rate class (Exh. C5-2-5);

(vi) total actual (non-weather normalized) throughput volumes by service type and rate class (Exh. C5-2-1);

(vii) total weather normalized gas sales revenue by service type and rate class (a new exhibit would have to be created for normalized revenue by rate class);

(viii) total actual (non-weather normalized) gas sales revenue by service type and rate class (Exh.C5-2-5);

(ix) T-service revenue, by service type and rate class (Exh. C5-2-1);

(x) total customers by service type and rate class (Exh. C5-2-1);

(xi) other revenue (Exh. C5-3-1);

(xii) operating and maintenance expense by department (Exh. D5-2-2);

(xiii) calculation of utility income taxes (Exh. D5-1-1, p.3);

(xiv) calculation of capital cost allowance (Exh. D5-1-1, p. 8);

(xv) provision of depreciation, amortization and depletion (Exh. D5-1-1, p. 4);

(xvi) capital budget analysis by function (Exh. B5-2-1); and

(xvii) statements of utility ratebase (Exh. B5-1-2, B5-1-3).

In addition to the information set out above, Enbridge agrees to prepare an ESM calculation that pertains to each year of the Term of the IR Plan following the release of its audited financial statements for that year. Enbridge will file this calculation (and an application for disposition of any amounts recorded in the ESMDA) as soon as is reasonably possible after year-end financial results have been made public, with the intention of clearing the ESMDA no later than the time of Enbridge's July 1 QRAM. The Parties agree that stakeholders, including all Parties, should have a reasonable opportunity to review the application and calculations, including the ability to make reasonable requests for additional information with respect thereto from Enbridge, and to make submissions or provide comments thereon.

- **Participating Parties:** All Parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue and GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-6- 1	Rate Filing Process and Report Requirements
I-1-23	Board Staff Interrogatory 23
I-11-68	SEC Interrogatory 68
JTB.26	SEC Undertaking 26 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-5-1	IGUA Evidence

11.2 What should be the frequency of the reporting requirements during the IR plan (e.g., quarterly, semi-annual or annually)?

- **Complete Settlement:** See the settlement of Issue 11.1 above.

11.3 What should be the process and the role of the Board and stakeholders?

- **Complete Settlement:** See the settlement of Issue 11.1 above.

B-6- 1	Rate Filing Process and Report Requirements
I-11-69	SEC Interrogatory 68
JTB.42	IGUA Undertaking JTB.42 to PEG
L-5-1	IGUA Evidence

12 RATE-SETTING PROCESS

12.1 Annual Adjustment

12.1.1 What should be the information requirements?

- **Complete Settlement:** The Company shall file the following information, by October 1st, for the purpose of receiving a Board-approved rate order by December 15th, stipulating new rates in each rate class, in time for implementation on January 1st of the following year:

  (i) the forecast of degree days and corresponding volumes for that rate year;

  (ii) the forecast of average number of active customers for that rate year;

  (iii) the determination of the inflation index, "GDP IPIFDD" for that rate year;

  (iv) the determination of the DRR, its allocation to rate classes and the resulting impact on prevailing rates;

(v) Y factors amounts and the associated cost-of-service distribution revenue requirement, for that rate year, and the allocation of those amounts to rate classes;

(vi) the amounts of requested Z factors, if any, and associated cost-of-service distribution revenue requirement, for that rate year, and the allocation of those amounts to rate classes;

(vii) deferral and variance account balances for the current rate year (eight months of actuals and four months of forecast) including the accounts proposed for clearance; the clearance of deferral and variance accounts will occur each year in conjunction with the July 1st QRAM and will clear the prior years December 31st year end actual balances;

(viii) a draft rate order; and

(ix) a rate handbook and supporting documentation detailing how rates have been adjusted to reflect the application of the Adjustment Formula.

Attached as Appendix C is a description of how the 2008 revenue per customer shall be determined, including schedules that set out the estimated distribution revenue impacts for the years 2008-2012. Appendix C is based on Exhibit C-4-1 but has been revised to reflect the terms and conditions of this Agreement.

Attached as Appendix D are schedules that set out the estimated tax rate and rule change impacts for the years 2008-2012. Attached as Appendix E are schedules that set out the estimated assignment of distribution revenue to rate classes (with and without Y factors) for the years 2008-2012 Enbridge agrees that the Board-approved cost allocation and rate design principles used to allocate the revenues on a per rate class basis for 2008 will be maintained throughout the term of the IR Plan unless the Company seeks the Board's approval for any proposed changes by filing an application with supporting materials and the Board so approves.

Attached as Appendix F is a schedule that sets out the estimated percentage rate increases for each rate class, for the years 2008-2012. Attached as Appendix G is a schedule that sets out the bill impacts for the years 2008-2012.

Enbridge agrees that if, as part of the annual rate-setting process, the proposed rate increases (if any), on a T-service basis, for any general service class rate and/or for any large volume rate class, exceed 3.0% and 1.5%, respectively, then it will file detailed evidence explaining the rate increases.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, SEC and Timmons.

- **Evidence:** The evidence that is relevant to these issues includes the following:

B-1-1	Incentive Regulation Proposal
B-6-1	Rate Filing Process and Report Requirements
D-3-1	PEG Report June 20, 2007
I-1-24	Board Staff Interrogatory 24
I-7-18	LPM Interrogatory 18
I-8-7	OAPPA Interrogatory 7
I-11-70	SEC Interrogatory 70
I-12-1	TransCanada Energy Interrogatory 1
I-13-18	VECC Interrogatory 18
JTB.42	IGUA Undertaking JTB.42 to PEG
JTA.55 and 57	Board Staff Undertaking 55 and 57 to EGD
JTA.68 and 69	BOMA/LPMA/WPSPGA Undertakings 68 and 69 to EGD
JTA.71 and 72	APPrO Undertakings 71 and 72 to EGD
JTB.1	IGUA Undertaking 1 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-4-1	PWU Evidence of Dr. Cronin
L-5-1	IGUA Evidence

12.1.2 What should be the process, the timing, and the role of the stakeholders?

- **Complete Settlement:** See the settlement of Issue 12.1.1

12.2 New Energy Services

12.2.1 What should be the criteria to implement a new energy service?

- **Complete Settlement:** Enbridge agrees that all proposed new regulated energy services will require Board approval. Accordingly, Enbridge will make application (with supporting materials), on notice, in respect of all proposed new regulated energy services.

- **Participating Parties:** All Parties participated in the negotiation and settlement of these issues.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on these issues: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.

- **Evidence:** The evidence that supports the settlement of these issues includes the following:

B-6-1	Rate Filing Process and Report Requirements
C-1-1	Summary of Gas Cost to Operation

C-1-2	Gas Costs Schedules
C-2-1	Gas Volume Budget
C-2-2	Degree Days
C-2-3	Average Use and Economic Assumptions
C-3-1	Customer Additions
C-4-1	2008 Revenue per Customer Cap
C-5-1	Rate Design
C-6-1	Rate Schedule
C-6-2	2008 Revenue Requirement by Rate Class
C-6-3	Proposed Volumes Revenues and Average Unit Rates By Class
C-6-4	Proposed Billed and Unbilled Revenue
C-6-5	Summary of Proposed Rate Change by Rate Class
C-6-6	Calculations of Gas Supply Charges by Rate Class
C-6-7	Detailed Revenue Calculations
C-6-8	Annual Bill Comparison EB-2007-0615 vs. EB-2007-0701
C-6-9	Assignment of Revenue Requirement
C-7-1	Y Factors - Capital Expenditure
C-7-2	Y-Factors - Safety and Reliability Projects Revenue Requirement Impact
C-7-3	Y-Factor- Leave to Construct Projects Revenue Requirement Impact
I-8-4	OAPPA Interrogatory 4
JTA.3	Pollution Probe Undertaking 3 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG

12.2.2 What should be the information requirements for a new energy service?

- **Complete Settlement:** See the settlement of Issue 12.2.1

12.3 Changes in Rate Design

12.3.1 What should be the criteria for changes in rate design?

Complete Settlement: In its Application, Enbridge proposed that it have certain flexibility to adjust rate design including, in particular, adjustments to the fixed/variable rate structure in some rate classes during the term of the IR Plan. Enbridge agrees that the current Board-approved rate design principles will be maintained throughout the term of the IR Plan unless changes are approved by the Board during the term of the IR Plan. The Parties agree that after rates are determined in accordance with any adjustment formula that the Board may adopt for Enbridge in this proceeding, no other adjustments shall be made, except for the following further adjustments:

Changes to Monthly Customer Charges

Monthly Customer Charges ($)		
Year	**Rate 1**	**Rate 6**
2008	14.00	50.00
2009	16.00	55.00
2010	18.00	60.00
2011	19.00	65.00
2012	20.00	70.00

The Parties also agree that:

(i) the above-noted changes shall be made on a revenue neutral basis within the rate class;

(ii) changes made to the volumetric charges should generally be done proportionately to the revenue recovered through each block, unless that produces inappropriate block relationships; and

(iii) for other rate classes, the Company will increase fixed and variable charges by an equal percentage.

Changes to Rate 135

The Parties agree to the Company's proposal to modify Rate 135 (Seasonal Firm Service) to create greater flexibility for customers who take service under this rate. Under the existing rate schedule, customers (who typically consume only during the spring, summer and fall) are required to deliver their mean daily volume ("MDV") on a 12-month basis. The Company compensates Rate 135 customers for their winter deliveries through a seasonal credit which is based on their MDV and paid from December to March.

The existing Rate 135 will continue to be available to customers as "Option A" within the rate schedule. An Option B will be added to permit customers to deliver gas over a nine-month (April to December) period. The calculation of the MDV for "Option B" will also be determined on a 9-month basis (i.e., a customer's annual forecast divided by nine months). Customers using "Option B" will continue to receive the seasonal credit for the month of December, but will not longer receive the seasonal credit during the months of January through March. As proposed in Exh. C-5-1, pp. 8-9, the Rate Handbook will reflect these two options for Rate 135: (a) the option to deliver their mean daily volume in the winter months or (b) the option of not being required to deliver their mean daily volume in the winter

Contract Demand Levels

Enbridge agrees to withdraw its proposal, described in Exhibit C-5-1, page 7, to amend the definition of Contract Demand. The Company also agrees not to advance this proposal during the term of the IR Plan.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

Approvals: All participating Parties accept and agree with the settlement except the following:

(i) GEC and Pollution Probe who do not support the agreement to increase the monthly customer charges for Rate 1 and 6 but who will not pursue this issue in the hearing; and

(ii) the following parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU and Timmins.

- **Evidence:** The evidence that is relevant to these issues includes the following:

B-1-1	Incentive Regulation Proposal
B-6-1	Rate Filing Process and Report Requirements
1-11-72 to 75	SEC Interrogatory 72 to 75
I-1-25	Board Staff Interrogatory 25
I-8-5 to 6	OAPPA Interrogatory 5 to 6
JTB.1	EGD Undertaking
JTB.6	EGD Undertaking
JTB.17	SEC Undertaking 17 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-I-1-1	Board/PEG November 14 Response to Union

12.3.2 How should the change in the rate design be implemented?

- **Complete Settlement:** See the settlement of Issue 12.3.1 above.

12.3.3 What should be the information requirements for a change in rate design?

- **Complete Settlement:** See the settlement of Issue 12.3.1 above.

12.4 Non-Energy Services

12.4.1 Should the charges for these services be included in the IR mechanism?

- **Complete Settlement:** The Parties agree that miscellaneous, regulated non-energy service charges shall be handled outside the Adjustment Formula. If Enbridge proposes any changes to miscellaneous non-energy service charges during the term of the IR Plan, it will provide the Board with evidence that supports the change. The Parties agree to the principle that non-energy service charges should not generate incremental revenue in excess of any related incremental costs.

Enbridge agrees that all new regulated non-energy services will require Board prior approval. Accordingly, Enbridge will make application (on notice) and with supporting materials, for all new regulated non-energy services.

- **Participating Parties:** All Parties participated in the negotiation and settlement of these issues.
- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on these issues: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.
- **Evidence:** The evidence that is relevant to these issues includes the following:

B-1-1	Incentive Regulation Proposal
B-6-1	Rate Filing Process and Report Requirements
I-11-76	SEC Interrogatory 76
JTB.42	IGUA Undertaking JTB.42 to PEG
L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)

12.4.2 If not, what should be the criteria for adjusting these charges?

- **Complete Settlement:** See the settlement of Issue 12.4.1

12.4.3 What should be the criteria to implement new non-energy services?

- **Complete Settlement: :** See the settlement of Issue 12.4.1

12.4.4 What should be the information requirements for new non-energy services?

- **Complete Settlement: :** See the settlement of Issue 12.4.1

13 REBASING

13.1 What information should the Board consider and stakeholders be provided with at the time of rebasing?

- **Complete Settlement:** Subject to the settlement of Issue 8.1, Enbridge agrees to provide a full cost of service filing (Phase I & II) at the time of rebasing, regardless of whether it applies to set rates for 2013 on a cost of service basis or otherwise.

  The Parties agree that the Board's minimum filing guidelines (where relevant and applicable) set out information that is sufficient for the purpose of initial filing of a rebasing application, subject to the usual discovery rights of intervenors. At the time of rebasing, the Company will provide 2011 actual, 2012 bridge and 2013 forecast information. In addition, it will provide historical plant continuity information for 2006, 2007, 2008, 2009 and 2010. In the event that an agreement is reached to extend the term of the IR Plan, as provided for in the settlement of Issue 8.1, the Company agrees to provide the same information that it would have otherwise provided at the time of a rebasing, in accordance with the settlement of this issue.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.

- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on these issues: GEC, Kitchener, Pollution Probe, PWU and Timmins.

- **Evidence:** The evidence that is relevant to these issues includes the following

B-1-1	Incentive Regulation Proposal
B-7-1	Rebasing Filing Requirements
I-1-27	Board Staff Interrogatory 27
I-7-20	LPM Interrogatory 20
I-11-77	SEC Interrogatory 77
L-4-1	PWU Evidence of Dr. Cronin
L-5-1	IGUA Evidence
L-I-1-1	Board/PEG November 14 Response to Union

14 ADJUSTMENTS TO BASE YEAR REVENUE REQUIREMENTS AND/OR RATES

14.1 Are there adjustments that should be made to base year revenue requirements and/or rates?

- **Complete Settlement:** The Parties agree that only the following additional adjustments (other than those adjustments otherwise set out in this Agreement) should be made to reduce the 2008 base revenue requirement and/or 2008 rates, prior to the application of the Adjustment Formula.

  (i) $9.2 million being the amount of the Notional Utility Account;

  (ii) $3.0 million in regulatory expenses (adjusting the variance account mechanism by the same amount); and

  (iii) adjustments to reflect the settlement of the tax rate change aspect of Issue 6.1, for 2008.

When final rates for 2008 are determined, the difference between final and interim rates will be recovered/rebated, either as a one-time charge/credit or over the remainder of 2008 in rates.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue Coral/Shell Energy.

  Approvals: All participating Parties accept and agree with the settlement except:

  (i) the following Parties who take no position on these issues: GEC, Kitchener, Pollution Probe, PWU, SEC, Timmins and Transalta; and

  (ii) SEC who agrees with the settlement with respect to adjustments (i) and (ii) above-described and takes no position with respect to the settlement of (iii) above-described.

- **Evidence:** The evidence that is relevant to these issues includes the following:

B-1-1	Incentive Regulation Proposal
B-6-1	Rate Filing Process and Report Requirements
EB-2005-0001	Decision with Reasons
EB-2006-0034	Decision
I-1-28	Board Staff Interrogatory 28
I-5-4 to 5	Energy Probe Interrogatories 4 to 5
I-11-78 to 80	SEC Interrogatories 79 to 80
I-13-19	VECC Interrogatory 19
JTB.24	SEC Undertaking 24 to EGD
L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)

14.2 If so, how should these adjustments be made?

- **Complete Settlement:** See the settlement of Issue 14.1 above.

Other Issue (not specifically included in Board's List of Issues): CIS Rate-Smoothing Proposal

Complete Settlement*:* On June 29, 2007, the Company applied for orders approving the method of recovery of the revenue requirement related to a new Customer Information System ("CIS") that was the subject of a settlement agreement ("CIS Agreement") approved by the Board on the EB-2006-0034 proceeding. The CIS Agreement provides that CIS costs of $124 million (subject to later adjustments) should be smoothed over five years between January 1, 2008 and December 2012 subject to the Company's right to apply for an approval of an alternative smoothing approach.

The Board decided that Enbridge's rate smoothing application for an alternative smoothing approach should be heard in the EB-2007-0615 proceeding. The application is included at Exhibit D-7-1.

Enbridge agrees not to proceed with the alternative rate-smoothing proposal described in the June 29, 2007 application during the term of the IR Plan with the result that, subject to true up, the taxes component of the CIS costs of $124 million will be smoothed over five years in accordance with the CIS Agreement including the schedules thereto.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.
- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on this issue: Coral/Shell Energy, GEC, Kitchener, OAPPA, Pollution Probe, PWU, Timmins and Transalta.
- **Evidence:** The evidence that is relevant to this issue includes the following:

D-7-1	Application dated June 29, 2007

List of Issues

Appendix A of Procedural Order No. 4

1 Multi-Year Incentive Ratemaking Framework

1.1 What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

1.2 What is the method for incentive regulation that the Board should approve for each utility?

1.3 Should weather risk continue to be borne by the shareholders, and if so what other adjustments should be made?

2 Inflation Factor

2.1 What type of index should be used as the inflation index (industry specific index or macroeconomic index)?

2.1.1 Which macroeconomic or industry specific index should be used?

2.2 Should the inflation index be based on an actual or forecast?

2.3 How often should the Board update the inflation index?

2.4 Should the gas utilities ROE be adjusted in each year of the incentive regulation (IR) plan using the Board's approved ROE guidelines?

3 X Factor

3.1 How should the X factor be determined?

3.2 What are the appropriate components of an X factor?

3.3 What are the expected cost and revenue changes during the IR plan that should be taken into account in determining an appropriate X factor?

4 Average Use Factor

4.1 Is it appropriate to include the impact of changes in average use in the Adjustment Formula?

4.2 How should the impact of changes in average use be calculated?

4.3 If so, how should the impact of changes in average use be applied (e.g., to all customer rate classes equally, should it be differentiated by customer rate classes or some other manner)?

5 Y Factor

5.1 What are the Y factors that should be included in the IR plan?

5.2 What are the criteria for disposition?

6 Z Factor

6.1 What are the criteria for establishing Z factors that should be included in the IR plan?

6.2 Should there be materiality tests, and if so, what should they be?

7 Natural Gas Electricity Interface Review (NGEIR) Decisions

7.1 How should the impacts of the NGEIR decisions, if any, be reflected in rates during the IR plan?

8 Term of the Plan

8.1 What is the appropriate plan term for each utility?

9 Off-Ramps

9.1 Should an off-ramp be included in the IR plan?

9.2 If so, what should be the parameters?

10 Earning Sharing Mechanism (ESM)

10.1 Should an ESM be included in the IR plan?

10.2 If so, what should be the parameters?

11 Reporting Requirements

11.1 What information should the Board consider and stakeholders be provided with during the IR plan?

11.2 What should be the frequency of the reporting requirements during the IR plan (e.g., quarterly, semi-annual or annually)?

11.3 What should be the process and the role of the Board and stakeholders?

12 Rate-Setting Process

12.1 Adjustment Formula

12.1.1 What should be the information requirements?

12.1.2 What should be the process, the timing, and the role of the stakeholders?

12.2 New Energy Services

12.2.1 What should be the criteria to implement a new energy service?

12.2.2 What should be the information requirements for a new energy service?

12.3 Changes in Rate Design

12.3.1 What should be the criteria for changes in rate design?

12.3.2 How should the change in the rate design be implemented?

12.3.3 What should be the information requirements for a change in rate design?

12.4 Non-Energy Services

12.4.1 Should the charges for these services be included in the IR mechanism?

12.4.2 If not, what should be the criteria for adjusting these charges?

12.4.3 What should be the criteria to implement new non-energy services?

12.4.4 What should be the information requirements for new non-energy services?

13 Rebasing

13.1 What information should the Board consider and stakeholders be provided with at the time of rebasing?

14 Adjustments to Base Year Revenue Requirements and/or Rates

14.1 Are there adjustments that should be made to base year revenue requirements and/or rates?

14.2 If so, how should these adjustments be made?

Deferral and Variance Accounts

The following is the list of Deferral Accounts ("DA's") and Variance Accounts ("VA's") agreed to by all Parties for the 2008 fiscal year, divided into three groupings – Gas related, Non-Gas related, and DSM related:

Gas related DA's and VA's

1. 2008 Purchased Gas VA ("PGVA"),
2. 2008 Transactional Services DA ("TSDA"),
3. 2008 Unaccounted for Gas VA ("UAFVA"), and
4. 2008 Storage and Transportation DA ("S&TDA").

Non-gas related DA's and VA's

5. 2008 Carbon Dioxide Offset Credits DA ("CDOCDA"),
6. 2008 Class Action Suit DA ("CASDA"),
7. 2008 Deferred Rebate Account ("DRA"),
8. 2008 Electric Program Earnings Sharing DA ("EPESDA"),
9. 2008 Gas Distribution Access Rule Costs DA ("GDARCDA"),
10. 2008 Manufactured Gas Plant DA ("MGPDA"),
11. 2008 Municipal Permit Fees DA ("MPFDA"),
12. 2008 Ontario Hearing Costs VA ("OHCVA"),
13. 2008 Open Bill Access VA ("OBAVA"),
14. 2008 Open Bill Service DA ("OBSDA"),
15. 2008 Unbundled Rate Implementation Cost DA ("URICDA"), and
16. 2008 Unbundled Rates Customer Migration VA ("URCMVA")
17. 2008 Average Use True-Up Variance Account ("AUTUVA")
18. 2008 Tax Rate and Rule Change Variance Account ("TRRCVA")

19. 2008 Earnings Sharing Mechanism Deferral Account ("ESMDA")

<u>DSM related DA's and VA's</u>

20. 2008 Demand-Side Management VA ("DSMVA"),
21. 2008 Lost Revenue Adjustment Mechanism ("LRAM"), and
22. 2008 Shared Saving Mechanism VA ("SSMVA").

2008 REVENUE PER CUSTOMER CAP, DISTRIBUTION REVENUE
AND TOTAL REVENUE DETERMINATION

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
Row		2008	2009	2010	2011	2012	
1.	2007 Total Board Approved Revenue Requirement	3,119.8					
2.	Gas Costs to operations (embedded above at July 1, 2006 ref. price)	2,174.6					
3.	2007 Board approved Distribution Revenue Requirement	945.2					
4.	Gas in storage related carrying cost 2007 approved	(59.5)					
5.	DSM 2007 approved amount	(22.0)					
6.	CIS / Cust. Care 2007 approved amount	(90.8)					
7.	Notional utility account adjustment	(9.2)					
8.	Regulatory expense adjustment	(3.0)					
9.	Distribution Revenue Sub-total	760.7	779.51	803.70	826.42	846.83	
10.	Ratepayer 50% share of tax amounts (Appendix D of N1-1-1)	(7.44)	(1.81)	(3.66)	(5.43)	(2.57)	
11.	Distribution Revenue base (subject to the escalation formula, $millions)	753.26	777.70	800.04	820.99	844.26	
12.	Average Number of Customers (Beginning)	1,823,258	1,864,047	1,905,047	1,946,047	1,987,047	
13.	Distribution Revenue per Customer (Beginning)	$ 413.14	$ 417.21	$ 419.96	$ 421.87	$ 424.88	
14.	GDP IPI FDD	2.04%	2.04%	2.04%	2.04%	2.04%	
15.	Inflation Coefficient (allowed % of GDP IPI FDD)	60.00%	55.00%	55.00%	50.00%	45.00%	
16.	Escalation Factor, 100 plus (GDP IPI FDD multiplied by the inflation coeff.)	101.22%	101.12%	101.12%	101.02%	100.92%	
17.	Distribution Revenue per Customer (Ending)	$ 418.18	$ 421.88	$ 424.66	$ 426.18	$ 428.79	
18.	Average Number of Customers (Ending)	1,864,047	1,905,047	1,946,047	1,987,047	2,028,047	
19.	Distribution Revenue (resulting from the escalation formula, $millions)	779.51	803.70	826.42	846.83	869.61	
20.	Gas in storage & working cash carrying costs (at Oct. 1, 2007 ref. price)	43.10	43.10	43.10	43.10	43.10	
21.	DSM amount (unknown beyond 2009)	23.10	24.30	24.30	24.30	24.30	
22.	CIS / Customer Care (placeholder illustrative from CIS/CC agreement)	89.20	89.20	89.20	89.20	89.20	
23.	Power generation projects	(0.10)	3.05	3.00	2.95	2.89	
24.	Total Y-Factors (estimates only for some)	155.30	159.65	159.60	159.55	159.49	
25.	Resulting 2008 Distribution Revenues plus estimate to 2012	934.81	963.35	986.02	1,006.38	1,029.10	4,919.66
26.	2008 Gas Costs to operations (at Oct. 1, 2007 ref. price)	1,929.00					
27.	2008 Total Revenue	2,863.81					
28.	Distribution Revenues of $934.81 vs. 2007 Board Approved of $945.2 M.	(10.39)					

Estimated Distribution Revenue Per Customer Cap

Determination (2008-2012)

Enbridge's revenue per customer cap calculation for 2008, as agreed to by the Parties to the Settlement Agreement and as shown on page 48 hereof, determines a 2008 total revenue amount to be collected through rates through the completion of the following process. (Formula amounts and %'s being referred to below are all found in column 1 on p. 48. Further, estimates of the 2009 -2012 distribution revenue component of rates exclusive of gas costs are also shown in columns 2 – 5, row 25 on p. 48 hereof.)

Process

1. Row 1, $3119.8 million, the starting point of the calculation, is the 2007 Total Board Approved revenue requirement as per the EB-2006-0034 Final Rate Order. (App. A, Schedule 5, Column 1, Line 22 or revenue at existing rates plus deficiency at Lines 28 + 29)

2. Row 2 eliminates the gas cost of $2,174.6 million embedded within that total approved revenue requirement to arrive at Row 3, the 2007 Board Approved distribution revenue requirement ("DRR") of $945.2 million. Removal of this gas cost is necessary as it was based on a July 1, 2006 gas cost reference price of $381.692 /10^{3}m^3 and was relative to 2007 approved volumes[1]. The elimination is required in order to establish a base distribution revenue upon which the incentive escalation formula can be applied exclusive of gas costs. A 2008 forecast gas cost, outside of the incentive escalation formula, is included into the 2008 total revenue at row 26, and is explained later in this evidence.

3. Row 3 shows the 2007 Board Approved DRR of $945.2 million to which the following further adjustments are required in order to calculate a distribution revenue upon which the incentive escalation formula can be applied within the context of Enbridge's revenue per customer cap model.

4. Row 4 shows a further elimination of $59.5 million which is the embedded carrying cost on gas in storage and working cash related to gas costs in the 2007 Board Decision which are eliminated and explained at row 2 above. Similar to row 2, this

[1] That reference price has been replaced within rates throughout each quarter in 2007 and the first quarter of 2008 through the QRAM process. The reference price at Oct. 1, 2007 and embedded in the forecast of gas cost at the time of the 2008 application was $323.347/10^{3}m^3.

elimination is required in order to remove the carrying cost on gas in storage and gas cost working cash embedded in the 2007 Board Approved DRR which was based on 2007 approved volumes and a July 1, 2006 gas cost reference price of $381.692 /10^{3}m^3. This elimination is necessary in order to establish a base distribution revenue upon which the incentive escalation formula can be applied exclusive of carrying costs on 2007 gas in storage and gas cost working cash amounts related to 2007 approved volumes and gas cost prices. A carrying cost on gas in storage and gas cost working cash for 2008, outside of the incentive escalation formula, is included in the 2008 total revenue and explained at row 20 later in this process. (Exh. C-T4-S1, App. A, pp. 1 & 2)

5. Row 5 removes the 2007 Board Approved DSM operating costs of $22.0 million as established within the EB-2006-0021 Decision. This adjustment is necessary as the 2008 DSM operating cost budget has already been approved in the above mentioned proceeding, therefore the base distribution revenue upon which the incentive escalation formula can be applied needs to exclude the 2007 approved amounts. The 2008 Board Approved DSM operating costs, outside of the incentive escalation formula, are included into the 2008 total revenue at row 21.

6. Row 6 removes the 2007 Board Approved CIS/Customer Care costs of $90.8 million (exclusive of bad debt). Again, this adjustment is necessary as the 2008 CIS/Customer Care cost will be determined by the associated true-up mechanism and CIS/Customer Care revenue requirement template as established in the EB-2006-0034 proceeding. Therefore the base distribution revenue upon which the incentive escalation formula is to be applied should exclude CIS/Customer Care costs. The 2008 allowable CIS/Customer Care costs will be included into the 2008 distribution revenues as established and agreed or approved within the true-up mechanism as explained at row 22.

7. Row 7 shows a reduction to base rates of $9.2 million, as a result of Parties to the Settlement Agreement agreeing to the removal of the amount embedded in 2007 rates in relation to the Notional Utility Account Recovery (settlement of Issue 14.1, para. (i), at p 39 hereof).

8. Row 8 shows a reduction to base rates of $3.0 million, as a result of Parties to the Settlement Agreement agreeing to reduce the level of regulatory proceeding related expenses embedded in 2007 rates by $3.0 million (settlement of Issue 14.1, para (ii), at p. 39 hereof).

9. Row 9 shows a distribution revenue sub-total of $760.7 million, inclusive of all of the above noted adjustments.

10. Row 10 shows a reduction to base rates of $7.44 million, as a result of Parties to the Settlement Agreement agreeing to a Z-factor related to tax rate and rule change

expectations, in which total tax amounts determined through the agreed to methodology are shared equally between ratepayers and the Company. The description and methodology agreed to for the 2008 amount and for the incremental amounts in 2009 through 2012, are found in the settlement of Issue 6.1 – Changes in Tax Rules and Rates – at pages 23-24 hereof.

11. Row 11 shows the base distribution revenue of $753.26 million, upon which the ADR Settlement Agreement incentive escalation formula can be applied.

12. Row 12 provides the 2007 Board Approved average number of customers of 1,823,258 (from EB-2006-0034, Ex.C3, Tab 2, Schedule 1, Item 5) which is used in the next step of this process to calculate the base distribution revenue dollar/customer before Y and other Z factors.

13. Row 13 is a 2007 base distribution revenue per customer of $413.14, which is derived by dividing the row 11 base distribution revenue of $753.26 million by the 2007 approved average customers of 1,823,258.

14. Row 14, 2.04%, is the GDP IPI FDD inflation factor component of the proposed incentive escalation formula as agreed to by Parties to the Settlement Agreement (settlement of Issue 2.1 at pp. 10-11 hereof).

15. Row 15, 60%, is the inflation coefficient component of the incentive escalation formula as agree to by Parties to the Settlement Agreement (settlement of Issue 3.1 at pp. 12-15 hereof).

16. Row 16, 101.22% (or a multiplier of 1.0122), is the escalation factor calculated as 100% plus 1.22% (1.22% is calculated as the GDP IPI FDD inflation factor of 2.04% multiplied by 70%), which is required in the next step to arrive at an escalated average distribution revenue dollar per customer amount.

17. Row 17, $418.18, is the 2008 distribution revenue per customer which is calculated by multiplying the 2007 distribution revenue per customer at row 13 of $413.14 by the escalation factor of 101.22% or a multiplier of 1.0122.

18. Row 18 provides the 2008 forecast average number of customers of 1,864,047 which is found in evidence at Exhibit C-2-1, Appendix A.

19. Row 19, $779.51 million, is the 2008 distribution revenue which is calculated by multiplying the 2008 distribution revenue per customer amount of $418.18 by the forecast 2008 average number of customers of 1,864,047. This distribution revenue is further adjusted in rows 20 through 26 to arrive at a 2008 total revenue for which 2008 rates will be developed.

20. Row 20 increases the $779.51 distribution revenue by $43.1 million for carrying costs on 2008 gas in storage and gas cost working cash. As explained in the row 4 narrative, just as the carrying costs embedded in the Board's 2007 approved DRR need to be removed from a DRR to apply an incentive escalation formula, the 2008 carrying cost on gas in storage and gas cost working cash related to 2008 forecast volumes and the Oct. 1, 2007 gas cost reference price needs to be included in the 2008 total revenue. This type of adjustment is required in order to develop rates which would incorporate subsequent years volumetric forecasts and changes in approved gas prices. (Exh. C-T4-S1, App. A, pp. 1 & 2)

21. Row 21 increases the $779.51 million distribution revenue by $23.1 million, which is the 2008 Board approved DSM operating costs as established in the EB-2006-0021 Decision. This is required to include a 2008 DSM amount into the 2008 total revenue to replace the previously removed 2007 DSM operating costs as explained in the narrative for row 5.

22. Row 22 will increase the $779.51 million distribution revenue by the 2008 amount of CIS/Customer Care costs which, as previously mentioned in the row 6 narrative, will be determined through the template and true-up mechanism established in the EB-2006-0034 proceeding. This amount will be determined upon the completion of the process required for the true-up mechanism as stipulated within the CIS / Customer Care Settlement Agreement. The schedule at page 1 of this exhibit includes an amount of $89.2 million for illustrative purposes only. This amount is shown as an illustration amount in EB-2006-0034, Exhibit N1, Tab 1, Schedule 1, Appendix F, page 25, Column B, Line 23.

23. Row 23, $(0.1) million, represents the 2008 revenue requirement amount agreed to by the Parties to the Settlement Agreement, for inclusion in the 2008 total revenue with respect to Y-factor capital expenditures for power generation leave to construct projects (settlement of Issue 5.1 at pp. 18-21 hereof).

24. Row 24 is the sum of rows 20, 21, 22 & 23.

25. Row 25, $934.81 million, represents the agreed to 2008 distribution revenue, subject to the amount required for row 22 to be determined through the CIS/Customer Care true-up mechanism.

26. Row 26, $1,929.0 million, is the 2008 forecast gas cost which is required to be included into the 2008 total revenue to replace the previously removed 2007 gas cost value embedded within the starting 2007 Total Board Approved revenue requirement as explained in the narrative for row 2.

27. Row 27, $2,863.81, is the 2008 total revenue agreed to by Parties to the Settlement Agreement, following the application of the sum of all of the elements of the agreed

upon incentive escalation formula. 2008 rates will be designed to recover this entire amount based on the forecast of 2008 volumes inherent in the formula and revenue amount derivation.

28. Row 28, $(10.39) million, is equal to row 25 minus row 3 and represents the change in the Distribution Revenue.

Summary - Sharing of Tax Change Forecast Amounts

Line No.	Tax Related Amounts Forecast from CCA Rate Changes ($ Millions)	Col. 1 2008	Col. 2 2009	Col. 3 2010	Col. 4 2011	Col. 5 2012	Col. 6
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45) - Opening UCC Balance	1.54	2.24	2.55	2.69	2.76	
6.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
7.	Capital Cost Allowance (CCA) at 55% - 2007 Federal Budget tax rule CCA rate	1.43	1.82	1.99	2.07	2.10	
8.	Closing Undepreciated Capital Cost (UCC)	2.24	2.55	2.69	2.76	2.78	
9.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.77	687.72	898.87	1101.58	
10.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
11.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
12.	Closing Undepreciated Capital Cost (UCC)	467.77	687.72	898.87	1101.58	1296.17	
13.	Distribution Assets (Class 1) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
14.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
15.	Capital Cost Allowance (CCA) at 6% - 2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
16.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
17.	CCA Difference	7.27	11.41	15.08	18.36	21.29	
18.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	32.00%	30.50%	29.00%	
19.	Tax Impact	2.44	3.76	4.83	5.60	6.17	
20.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.66	5.62	7.10	8.06	8.69	33.13
21.	Incremental Amount	3.66	1.95	1.48	0.96	0.64	
22.	**50% of the Amount to Reduce Rates**	**$1.83**	**$0.98**	**$0.74**	**$0.48**	**$0.32**	
	Tax Related Amounts Forecast from Income Tax Rate Changes						
23.	Taxable Income (2007 Board Approved, Final Rate Order, App.A, S3,P3,L15)	355.6	355.6	355.6	355.6	355.6	
24.	Gross Deficiency (2007 Board Approved, Final Rate Order, App.A, S1,P1,L7)	42.7	42.7	42.7	42.7	42.7	
25.	Interest Expense (2007 Board Approved, Final Rate Order, App.A, S3,P3,L25)	(165.90)	(165.90)	(165.90)	(165.90)	(165.90)	
26.	Board Approved Taxable Income for Income Tax Expense Calculation	232.40	232.40	232.40	232.40	232.40	
27.	2007 Approved Tax Rate (2007 Board Approved, Final Rate Order, App.A, S3,P3,L27)	36.12%	36.12%	36.12%	36.12%	36.12%	
28.	Anticipated Tax Rates During the IR Term	33.50%	33.00%	32.00%	30.50%	29.00%	
29.	Tax Rate Variance	2.62%	3.12%	4.12%	5.62%	7.12%	
30.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	9.57	13.06	16.55	
31.	Grossed-up Tax Savings	9.16	10.82	14.07	18.79	23.31	76.15
32.	Incremental Amount	9.16	1.66	3.25	4.72	4.52	
33.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$1.63**	**$2.36**	**$2.25**	
	Tax Related Amounts Forecast from Capital Tax Rate Changes						
34.	2007 Taxable Capital as Filed (EB-2006-0034, D3,T1,S1,P6,L7)	3,571.0	3,571.0	3,571.0	3,571.0	3,571.0	
35.	2007 Decision and Settlement Agreement Adjustments to Taxable Capital	(118.8)	(118.8)	(118.8)	(118.8)	(118.8)	
36.	2007 Board Approved Taxable Capital	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
37.	2007 Board Approved Capital Tax Rate (EB-2006-0034, D3,T1,S1,P6,L8)	0.285%	0.285%	0.285%	0.285%	0.285%	
38.	Anticipated Capital Tax Rates During the IR Term	0.225%	0.225%	0.150%	0.000%	0.000%	
39.	Capital Tax Rate Variance	0.060%	0.060%	0.135%	0.285%	0.285%	
40.	Annual Capital Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	2.07	2.07	4.66	9.84	9.84	28.48
41.	Incremental Amount	2.07	0.00	2.59	5.18	0.00	
42.	**50% of the Amount to Reduce Rates**	**$1.03**	**$0.00**	**$1.29**	**$2.59**	**$0.00**	
43.	**Cumulative Total Forecast Tax Related Amount (lines 20+31+40)**	**14.89**	**18.51**	**25.83**	**36.69**	**41.84**	**137.76**
44.	**Total Incremental Ratepayer Amounts into rates (lines 21+32+41)**	**$7.44**	**$1.81**	**$3.66**	**$5.43**	**$2.57**	
45.	**Total Annual Ratepayer Tax Savings (50% of row 43)**	**$7.44**	**$9.25**	**$12.91**	**$18.34**	**$20.91**	**$68.85**
46.	**50% Ratepayer and Company Shareholder ESM Amount During the IR Term**	**$68.85**					

Estimated Assignment of 2008-2012 Distribution Revenue (With and Without Y Factors) to Rate Classes

2008

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	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	Total DRR	934.8	627.1	244.3	1.2	25.5	10.4	7.9	3.5	0.7	4.6	5.1	2.1	0.3	0.2	1.6
	Y Factor: Other															
1.1	2008 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2008 Board Approved Amount	23.1	11.2	5.8	-	2.3	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2008	89.2	81.7	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2008 Leave to Construct	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	
	Total Y-Factor Revenue requirement	155.3	113.0	30.6	0.0	4.6	1.3	1.5	(0.0)	0.1	1.1	2.5	0.5	0.0	0.0	-
	Total DRR minus Y-Factor	779.5	514.0	213.6	1.2	20.9	9.2	6.4	3.5	0.6	3.5	2.6	1.6	0.3	0.2	1.6

Estimated Assignment of 2008-2012 Distribution Revenue (With and Without Y Factors) to Rate Classes

2009

Col. 1 ITEM NO.	Col. 2 DESCRIPTION	Col. 3 TOTAL	Col. 4 RATE 1	Col. 5 RATE 6	Col. 6 RATE 9	Col. 7 RATE 100	Col. 8 RATE 110	Col. 9 RATE 115	Col. 10 RATE 125	Col. 11 RATE 135	Col. 12 RATE 145	Col. 13 RATE 170	Col. 14 RATE 200	Col. 15 RATE 300 Firm	Col. 16 RATE 300 Int	Col. 17 DIRECT PURCHASE
	Total DRR	963.3	643.9	251.4	1.2	26.3	10.7	8.1	6.3	0.7	4.7	5.2	2.2	0.3	0.2	1.6
	Y Factor: Other															
1.1	2009 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2009	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2009	89.2	82.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2009 Leave to Construct	3.1	1.4	1.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	159.6	115.5	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	-
	Total DRR minus Y-Factor	803.7	528.4	219.6	1.2	21.4	9.4	6.6	6.1	0.6	3.6	2.7	1.6	0.3	0.2	1.6

Estimated Assignment of 2008-2012 Distribution Revenue (With and Without Y Factors) to Rate Classes

2010

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	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	Total DRR	986.0	659.8	256.9	1.3	27.0	10.9	8.2	6.4	0.7	4.8	5.2	2.3	0.3	0.2	1.6
	<u>Y Factor: Other</u>															
1.1	2010 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2010	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2010	89.2	82.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	<u>Y Factor: Capital Investment</u>															
1.4	2010 Leave to Construct	3.0	1.4	1.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	159.6	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	-
	Total DRR minus Y-Factor	826.4	544.3	225.1	1.3	22.1	9.6	6.7	6.2	0.6	3.7	2.7	1.7	0.3	0.2	1.6

Estimated Assignment of 2008-2012 Distribution Revenue (With and Without Y Factors) to Rate Classes

2011

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	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	Total DRR	1,006.4	673.5	262.2	1.3	27.6	11.2	8.4	6.4	0.7	4.9	5.3	2.3	0.4	0.2	1.6
	Y Factor: Other															
1.1	2011 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2011	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2011	89.2	82.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2011 Leave to Construct	3.0	1.3	1.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	159.5	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	-
	Total DRR minus Y-Factor	846.8	558.1	230.4	1.3	22.6	9.8	6.8	6.3	0.6	3.8	2.8	1.7	0.4	0.2	1.6

Estimated Assignment of 2008-2012 Distribution Revenue (With and Without Y Factors) to Rate Classes

2012

Col. 1 ITEM NO.	Col. 2 DESCRIPTION	Col. 3 TOTAL	Col. 4 RATE 1	Col. 5 RATE 6	Col. 6 RATE 9	Col. 7 RATE 100	Col. 8 RATE 110	Col. 9 RATE 115	Col. 10 RATE 125	Col. 11 RATE 135	Col. 12 RATE 145	Col. 13 RATE 170	Col. 14 RATE 200	Col. 15 RATE 300 Firm	Col. 16 RATE 300 Int	Col. 17 DIRECT PURCHASE
	Total DRR	1,029.1	688.8	268.1	1.3	28.2	11.4	8.6	6.5	0.7	5.0	5.4	2.4	0.4	0.2	1.6
	Y Factor: Other															
1.1	2012 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2012	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2012	89.2	82.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2012 Leave to Construct	2.9	1.3	1.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	159.5	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	-
	Total DRR minus Y-Factor	869.6	573.4	236.4	1.3	23.2	10.1	7.0	6.3	0.7	3.9	2.9	1.8	0.4	0.2	1.6

Estimated Rate Impacts (2008-2012)

ESTIMATED 2008-2012 RATE IMPACTS

Rate Class	ADR 2008[1] T-Service Rate Impact	ADR 2009[2] T-Service Rate Impact	ADR 2010[3] T-Service Rate Impact	ADR 2011[4] T-Service Rate Impact	ADR 2012[5] T-Service Rate Impact
1	0.1%	2.1%	1.6%	1.5%	1.7%
6	0.0%	1.8%	1.3%	1.2%	1.4%
9	0.1%	0.8%	1.1%	1.2%	1.6%
100	0.1%	1.3%	1.0%	0.9%	0.9%
110	0.1%	1.1%	1.0%	0.9%	0.9%
115	0.1%	1.1%	0.8%	0.8%	0.8%
135	0.6%	0.9%	0.9%	0.9%	0.9%
145	0.2%	1.0%	0.9%	0.8%	0.8%
170	0.4%	1.0%	0.9%	0.9%	0.9%
200	0.4%	1.0%	0.9%	0.8%	1.0%

	ADR 2008 Distribution Rate Impact	ADR 2009 Distribution Rate Impact	ADR 2010 Distribution Rate Impact	ADR 2011 Distribution Rate Impact	ADR 2012 Distribution Rate Impact
125	0.0%	0.7%	0.7%	0.7%	0.7%
300	0.1%	0.9%	0.9%	0.9%	0.9%

Notes:
1. - 2008 Distribution Revenue Requirement of $935 M
2. - 2009 Distribution Revenue Requirement of $963 M
3. - 2010 Distribution Revenue Requirement of $986 M
4. - 2011 Distribution Revenue Requirement of $1,006 M
5. - 2012 Distribution Revenue Requirement of $1,029 M

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Estimated Bill Impacts (2008-2012)

Sample Typical Customer Estimated T-Service Bill Impacts from 2008 to 2012
As Per Settlement Proposal

	October 1, 2007 T-Service Bill (1) Annual Bill ($)	Estimated 2008 T-Service Bill Annual Bill ($)	Estimated 2008 Annual $ change	Estimated 2009 T-Service Bill Annual $ change	Estimated 2010 T-Service Bill Annual $ change	Estimated 2011 T-Service Bill Annual $ change	Estimated 2012 T-Service Bill Annual $ change	Total 2008-2012 T-Service Bill Cumulative $ change	Cumulative % change
Rate 1									
Rate 1 T-Service Bill Impact	409.37	416.18	6.81	8.68	6.93	6.45	7.58	36.44	8.9%
Note: (1) based on annual consumption of 1,955 m3									
Rate 1 T-Service Bill Impact	558.77	559.89	1.12	11.67	9.32	8.67	10.19	40.98	7.3%
Note: (1) based on annual consumption of 3,064 m3									
Rate 1 T-Service Bill Impact	772.67	755.35	(17.32)	15.75	12.57	11.70	13.75	36.45	4.7%
Note: (1) based on annual consumption of 4,691 m3									
Rate 6									
Rate 6 T-Service Bill Impact	2,879.90	2,882.78	2.88	51.73	39.42	36.71	42.53	173.27	6.0%
Note: (1) based on annual consumption of 22,606 m3									
Rate 6 T-Service Bill Impact	5,023.61	4,710.21	(313.40)	84.52	64.40	59.99	69.50	-34.99	-0.7%
Note: (1) based on annual consumption of 43,285 m3									
Rate 115									
Rate 115 T-Service Bill Impact	3,356,188	3,359,796	3,608	36,958	25,691	25,723	25,969	117,948	3.5%
Note: (1) based on annual consumption of 69,832,850 m3 at 80% Load Factor									

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
BALANCES

Line No.	Account Description	Account Acronym	Col. 1 December 31, 2007 Principal ($000's)	Col. 2 December 31, 2007 Interest ($000's)	
	Non Commodity Related Accounts				
1.	Demand Side Management Account V/A	2007 DSMVA	(616.1)	(95.0)	
2.	Demand Side Management Account V/A	2006 DSMVA	374.7	(21.7)	
3.	Demand Side Management Account V/A	2005 DSMVA	697.5	23.2	
4.	Lost Revenue Adjustment Mechanism	2007 LRAM	-	-	
5.	Lost Revenue Adjustment Mechanism	2006 LRAM	(339.5)	(1.5)	
6.	Lost Revenue Adjustment Mechanism	2005 LRAM	(832.3)	(3.6)	
7.	Shared Savings Mechanism V/A	2007 SSMVA	-	-	
8.	Shared Savings Mechanism V/A	2006 SSMVA	11,229.1	-	
9.	Shared Savings Mechanism V/A	2005 SSMVA	-	-	
10.	Class Action Suit D/A	2007 CASDA	23,545.0	1,165.1	
11.	Deferred Rebate Account	2007 DRA	466.0	4.0	
12.	Debt Redemption D/A	2007 DRDA	(2,575.6)	(27.9)	
13.	Gas Distribution Access Rule Costs D/A	2007 GDARCDA	6,982.6	206.0	
14.	Ontario Hearing Costs V/A	2007 OHCVA	2,555.5	32.6	
15.	Manufactured Gas Plant D/A	2007 MGPDA	80.3	3.3	
16.	Electric Program Earnings Sharing D/A	2007 EPESDA	(308.7)	-	
17.	Corporate Cost Allocation Methodology D/A	2006 CCAMDA	475.2	23.3	
18.	Customer Care V/A	2007 CCVA	1,736.6	-	
19.	Unbundled Rate Implementation Cost D/A	2007 URICDA	199.3	7.6	
20.	Open Bill Service D/A	2007 OBSDA	574.1	46.2	
21.	Open Bill Access V/A	2007 OBAVA	146.8	-	
22.	Total non commodity related accounts		44,390.5	1,361.6	
	Commodity Related Accounts				
23.	Purchased Gas V/A	2007 PGVA	(137,102.5)	(4,060.7)	a)
24.	Transactional Services D/A	2007 TSDA	(8,698.4)	(99.4)	
25.	Unaccounted for Gas V/A	2007 UAFVA	6,112.1	-	
26.	Union Gas D/A	2007 UGDA	3,294.5	64.7	
27.	Total Commodity related accounts		(136,394.3)	(4,095.4)	
28.	Total deferral and variance accounts		(92,003.8)	(2,733.8)	

Notes:

a) PGVA balance is being cleared through Rider "C" treatment and unit rates as approved in the January 1, 2008 QRAM, EB-2007-0897. One time true up amount to be determined and proposed for clearance at time of July 1, 2008 QRAM.

b) Other than PGVA clearance none of the amounts shown have yet received Board Approval for clearance. The Company will file a schedule of balances and proposal for timing of clearances for review and approval by the end of February 2008.