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")

DSM related DA's and VA's

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

Row		Col. 1 2008	Col. 2 2009	Col. 3 2010	Col. 4 2011	Col. 5 2012	Col. 6
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 /$10^3m^3$ 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/$10^3m^3$.

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 /$10^3m^3$. 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.

Line No.	Summary - Sharing of Tax Change Forecast Amounts	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Tax Related Amounts Forecast from CCA Rate Changes ($ Millions)	**2008**	**2009**	**2010**	**2011**	**2012**	
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	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	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
	Y Factor: Other															
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	
	Y Factor: Capital Investment															
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	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	1,029.1	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 2008 Distribution Rate Impact	ADR 2009[2] T-Service Rate Impact	ADR 2009 Distribution Rate Impact	ADR 2010[3] T-Service Rate Impact	ADR 2010 Distribution Rate Impact	ADR 2011[4] T-Service Rate Impact	ADR 2011 Distribution Rate Impact	ADR 2012[5] T-Service Rate Impact	ADR 2012 Distribution 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%	
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 4,891 m3									
Rate 6									
Rate 6 T-Service Bill Impact	2,879.90	2,882.78	2.88	51.73	39.42	38.71	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 69,832,650 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.

Customer Care and CIS Settlement Template - (True-Up Template)

#	Category of Cost	A 2007	B 2008	C 2009	D 2010	E 2011	F 2012	G Totals
	CIS Related Categories							
1	*Old CIS Licence Fee*							
2	*Old CIS Hosting and Support*	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000
2a	*Incumbent (CWLP) CIS Services being provided from January to March 2007*							
3	*New CIS Capital Cost @ Board Approved **36%** Equity*	$0	$0	$950,000	($5,260,000)	$25,890,000	$24,910,000	$46,490,000
4	*New CIS Hosting and Support*	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000
5	*CIS Backoffice (EGD Staffing)*	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254
6	*SAP Licence Fees*	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500
7	*SAP Modifications*	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000
	Customer Care Related Categories							
8	*Incumbent (CWLP) Customer Care Services being provided from - January to March 2007*	$16,900,000	$0	$0	$0	$0	$0	$16,900,000
9	*Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sept. 30, 2008*	$0	$0	$0	$0	$0	$0	$0
10	*New Service Provider Contract Cost*	$47,803,098	$66,069,140	$67,251,948	$68,885,212	$70,731,432	$72,542,088	$393,282,918
11	*Customer Care Licences*	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000
12	*Customer Care Backoffice (EGD staffing)*	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071
13	*Customer Care Procurement Costs*	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000
14	*Transition Costs - Consultants and ISP*	$0	$0	$0	$0	$0	$0	$0
15	*Transition Costs - EGD Staffing*							
16	**Total CIS & Customer Care**	$84,403,098	$82,472,140	$87,234,238	$83,379,666	$115,539,309	$116,538,292	$569,566,743
17	*Number of Customers*	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613

	True-Up Process Step	A	B	C	D	E	F	G
18	*The Normalized 2007 Customer Care Revenue Requirement can be determined. This will be calculated by starting with the Total Customer Care Revenue Requirement for 2007 to 2012, which is the amount in box G16*	$569,566,743						
19	*That Total Customer Care Revenue Requirement will then be placed into an amortization model that calculates, using the IR annual adjustment that is approved for Enbridge Gas Distribution, the Normalized 2007 Customer Care Revenue Requirement which is the number that, when adjusted for IR annual adjustment for each year from 2008 through 2012, will allow the Company to fully recover the Total Customer Care Revenue Requirement for 2007 to 2012 [Sample calculation using the following formula as the Amortization Model: Adjusted Customer Care Revenue Requirement for 2008 to 2012 = ACRR IR Annual Adjustment = IRAA Term of IR = TOIR Normalized 2008 Customer Care Revenue Requirement = N2008CCRR N2008CCRR = ACRR - (ACRR + (ACRR) (- IRAA)] ((1+IRAA)^TOIR - 1)*	$90,799,999.40						
20	*The Normalized 2007 Customer Care Revenue Requirement will then be compared to the 2007 placeholder of $90.8 million, and the difference will be the 2007 Customer Care Revenue Requirement Variance.*	($1)						
21	*The Company will credit or debit the 2007 Customer Care Revenue Requirement Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012.*		($0)	($0)	($0)	($0)	($0)	
22	***The Normalized 2008 Customer Care Revenue Requirement will be the Normalized 2007 Customer Care Revenue Requirement, plus or minus the IR annual adjustment that is approved for Enbridge Gas Distribution.***	**$90,799,999**	**$92,412,426**	**$94,053,486**	**$95,723,687**	**$97,423,549**	**$99,153,596**	$569,566,743
23	*Total Customer Care Revenue By Year (Including repayment of 2007 variance)*	$ 90,800,000	$ 92,412,426	$ 94,053,486	$ 95,723,687	$ 97,423,549	$ 99,153,596	$ 569,566,743
24	*Normalized Customer Care Revenue Requirement Per Customer without Bad Debt*	$ 49.58	$ 49.21	$ 48.84	$ 48.50	$ 48.19	$ 47.91	
25	*Annual Adjustment assumed in above calcs.*	***1.7758%***						

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0021

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

AND IN THE MATTER OF a generic proceeding initiated by the Ontario Energy Board to address a number of current and common issues related to demand side management activities for natural gas utilities.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

August 25, 2006

EXECUTIVE SUMMARY

The Ontario Energy Board (the "Board") determined the original regulatory framework for gas utility sponsored Demand Side Management ("DSM") programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, Union Gas Limited ("Union") and Enbridge Gas Distribution Inc, ("EGD") have been filing DSM plans in response to the directives of the Board in the EBO 169-III Report.

In the Board's EB-2005-0001 decision dealing with EGD's 2006 rates, the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities – this decision. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act. The Board's findings in this decision, therefore, are orders of the Board pursuant to section 36 of the Act.

At the beginning of the oral hearing the Board was presented several documents which segmented the issues list into four categories. The categories consisted of a list of completely settled issues, a list of partially settled issues to which most intervenors and the utilities agreed, a list of partially settled issues to which all intervenors agreed with the exception of the utilities, and, a list of completely unsettled issues. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The Board's decision deals with a large number of issues relating to DSM. Generally, a rules-based and framework approach has been established where

appropriate and practical. Below is a list of the broader matters that have been decided.

- A three-year term for the first DSM plan
- Processes for adjustments during the term of the plan
- Formulaic approaches for DSM targets, budgets, and utility incentives
- Determination of how costs should be allocated to rate classes
- A framework for determining savings
- A framework and process for evaluation and audit
- The role of the gas utilities in electric Conservation and Demand Management activities and initiatives

The Board will issue a Procedural Order to commence the next phase dealing with the determination of the input assumptions after which the gas utilities can file their respective three-year DSM plans.

DECISION –PHASE 1

CHAPTER 1 - INTRODUCTION

The Ontario Energy Board (the "Board") determined the original regulatory framework for gas utility sponsored Demand Side Management ("DSM") programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, the gas utilities have filed DSM plans in response to the directives of the Board in the EBO 169-III Report.

The EBO 169-III Report provided guidelines to assist the utilities in the development and implementation of their respective DSM plans. Although the objectives and principles have evolved somewhat over the years to reflect changing market and industry conditions, they remain essentially unchanged. These DSM plans formed part of the gas utilities rate cases and were reviewed annually.

Over the past decade there have been occasions where rules for DSM programs have been challenged, requiring further interpretation and scrutiny by the Board. In addition, the Board has been required to frequently make decisions on similar DSM issues for the two large gas utilities, Union Gas Limited ("Union") and Enbridge Gas Distribution ("EGD"), in separate proceedings. This has lead to increased regulatory burden for all parties and inconsistent practices by the two utilities. These concerns and the heightened focus on conservation and demand side management for the energy sector as a whole were the impetus for the Board to re-examine the DSM regime as it pertains to these two gas utilities through this generic proceeding.

In the Board's partial decision in EGD's 2006 rates application (EB-2005-0001 / EB-2005-0437), the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act, 1998 (the "Act"). The Board's findings in this decision, therefore, should be considered orders pursuant to section 36 of the Act.

The Notice further stated that the following would be among the topics the Board would evaluate in making orders relating to the operation, evaluation and auditing DSM plans starting January 1, 2007:

- timing of the schedule for submitting and reviewing DSM plans,
- determination and use of planning assumptions for generic energy efficiency measures and custom projects,
- DSM budget as a percentage of utility annual revenue,
- structure and screening of programs including differentiating between market transformation, lost opportunity and enabling activities,
- structure and use of LRAM, SSM and DSMVA,
- process and content of program evaluations including the requirement for a third party audit process,
- length of plan, as well as updating the plan and reporting requirements,
- rules respecting free riders and attribution of energy savings, and
- the appropriateness of directing specific DSM measures to low-income consumers.

Other areas of focus will include the requirement for and role of the Consultative committee, filing requirements for the DSM plans and reporting requirements.

As the content of the topic list indicates, the intent of the proceeding was to streamline processes, harmonize practices where appropriate and re-examine the rules of DSM that had developed to date.

It was not the intent to revisit the general principles adopted and conclusions reached in the Report of the Board E.B.O. 169 III regarding the appropriateness of Demand Side Management being utilized by the Utilities in Integrated Resource Planning (IRP).

In the course of the proceeding, the Board received three settlement agreements. The first was a complete settlement on some of the issues. The other two were partial settlements.

The first partial settlement contained issues that were settled as between EGD and Union on the one hand, and most of the intervenors on the other. Some of the issues in this package dealt with the financial issues and this "financial package" was considered by the parties to be un-severable. That is to say that the parties to this partial agreement regarded each of the elements of the package to be crucial to the package as a whole. Were the Board to disapprove of any discrete element of the package, the package as a whole would be withdrawn, and each of the elements would have to be litigated.

The second partial settlement contained proposals that were agreed to by all intervenors but not the utilities.

The Board held an oral hearing that commenced on July 10, 2006. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The non-utility parties to the hearing were Canadian Manufacturers & Exporters ("CME"), Consumers Council of Canada ("CCC"), Energy Probe, Green Energy Coalition ("GEC"), Industrial Gas Users Association ("IGUA"), London Property Management Association ("LPMA"), Low Income Energy Network ("LIEN"),

Pollution Probe, School Energy Coalition ("SEC") and Vulnerable Energy Consumer's Coalition ("VECC").

The full record of the proceeding is available at the Board's offices. The Board has considered the full record but has summarized it in this decision to the extent necessary to provide context for its findings.

Chapter 2 deals with details of the completely settled issues. Chapter 3 addresses the issues contained in the "financial package". Chapter 4 deals with the remaining issues. Chapter 5 deals with the issues respecting a common set of input assumptions, a common guide and with next steps. In that regard, this decision document is referred to as Phase 1. Appendix 1 contains details regarding some of the procedural aspects of the proceeding, including a list of parties' representatives and witnesses.

CHAPTER 2 - THE SETTLEMENT PROPOSAL

A Settlement Proposal was filed with the Board on July 8, 2006 and was updated on July 11, 2006. The Board heard submissions from the parties and accepted the Settlement Proposal on July 11, 2006.

The Board acknowledges the effort of the participating parties to the Settlement Proposal and is pleased with the significant number of issues that were settled prior to the oral hearing.

Below are the completely settled issues which were accepted by the Board. To provide context to the balance of this decision, the Board sets out below the agreed upon phrasing of the settled issues. The numbering in brackets reflects the numbering that appeared on the Board's approved issues list for the proceeding.

Is a three year plan an appropriate term of a DSM plan? (Issue 1.2)

> "Parties agree that 3 years is an appropriate term for a multi-year DSM plan. Parties agree that the issue of whether and, if so, how a multi-year DSM plan should be aligned with a Utility's Incentive Regulation ("IR") period should be determined by the Board in the context of establishing the IR mechanism and rules, and cannot be determined in this proceeding in the absence of information on the structure and term of the IR regime adopted by the Board."

How are DSM parameters adjusted inside a multi-year rate making process? (Issue 1.6)

Parties referred this issue to completely settled Issue 1.2.

Should budgets, programs, targets, incentives and other plan components be established on an annual or multi-year basis? (Issue 1.8)

> "The approval of multi-year DSM plans will provide the utilities with the certainty of funding for programs which will have forecast life spans of more than one year. DSM plan components will be established at the outset of a multi-year DSM plan with the intention of applying throughout the currency of the multi-plan plan.
>
> As this settlement provides that the budget, SSM mechanism, LRAM, and DSMVA are all developed and measured on an annual basis within a multi-year plan, it is appropriate that amounts be recorded in all DSM variance or deferral accounts on an annual basis (market transformation amounts may be an exception)."

How should the budget be allocated between customer classes in rates? (Issue 1.9)

> "Cost allocation in rates shall be on the same basis as budgeted DSM spending by customer class. This allocation should apply to both direct and indirect DSM program costs."

Should the TRC [Total Resource Cost] test be the only test used to screen measures and/or programs for DSM plans? If no, what other tests should be used and how should these be applied? (Issue 2.1)

> "TRC shall be the only formal screen to determine whether a measure or program can be considered for inclusion in the portfolio. EBO 169-III identified numerous other considerations and tests that could be used to determine which measures and programs are actually selected for the portfolio in any given year, and those considerations and tests should continue to apply."

How should free rider and savings input assumptions be determined? (Issue 3.1)

"Parties agree that input assumptions such as free rider rates, prescriptive measure savings assumptions, incremental equipment costs, measure lives and avoided costs (natural gas, electricity and water) shall be based on research utilizing the best available data at the time a multi-year plan or new program or significant new program design is developed. These assumptions shall be assessed for reasonableness prior to implementation of the plan or program and should be reviewed and updated on a regular basis during the plan period as part of each Utility's ongoing evaluation and audit processes."

What certainty is required that the assumptions are set for the duration of the DSM plan? (Issue 3.3)

"The time at which changes in assumptions become effective shall differ depending on the use to which the assumption is being put:

Program Design and Implementation. The Utilities agree to the principle that their DSM programs should be managed with regard to the best available information known to them from time to time. Normal commercial practice requires that a Company should react through changes to program design, implementation and/or mix, to material changes in base data as soon as is feasible given relevant operational considerations.

LRAM. Assumptions used will be best available at the time of an audit. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for LRAM purposes from the beginning of 2007 onwards until changed again.

SSM. Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again."

What is the mechanism to determine if an input assumption needs to be reviewed or researched? (Issue 3.4)

"The Utility may of its own initiative or at the request of the Evaluation and Audit Committee ("EAC") commence a review of or research into assumptions."

How should the (LRAM) mechanism be structured? (Issue 4.2)

"The parties agree that the LRAM mechanism shall be calculated using the assumptions and savings estimates approved in the plan and adjusted for the audited Evaluation Report results.

For Union, the first year impact will be calculated as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

For EGD, the first year impact will be calculated on a monthly basis based on the volumetric impact of measures implemented in that month multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

Both of these processes for the Utilities reflect the status quo.

The LRAM account shall be cleared annually.

For purposes of clearing LRAM, input assumptions will be adjusted on an annual basis, as a result of the evaluation and audit work completed and shall apply from the beginning of the year being audited. See also Issue 3.3."

What evidence should be submitted to demonstrate that all conditions for clearance have been met? (Issue 4.3)

"Parties agree that the Utilities shall file an Audit report and any other backup needed to support the volumes used in the LRAM calculation. The Audit report will be prepared by an independent auditor to ensure accordance with Board approved rules. The auditor shall provide an opinion on the LRAM proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in Issue 9.3."

Is a third party audit required to verify LRAM calculation prior to clearance? (Issue 4.4)

"Yes, see issue 4.3 above."

How should LRAM costs be allocated between customer classes? (Issue 4.5)

"The LRAM shall be recovered in rates on the same basis as the lost revenues were experienced so that the LRAM ends up being a full true-up by rate class."

Should an incentive mechanism be in place? If yes, (Issue 5.1)

"Yes."

Is a third party audit required to verify year-end SSM calculation? And if required, what should be the audit principles, scope and timeline? (Issue 5.3)

"Parties agree that an independent auditor shall complete an evaluation audit with the purpose of verifying the claimed financial results and that

the DSM shareholder incentive amounts (being the SSM and the incentive available in respect of market transformation programs) are calculated in accordance with the Board approved methodology. The audit shall provide an opinion on the DSM shareholder incentive amounts proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in issue 9.3."

How should SSM costs be allocated between customer classes? (Issue 5.4)

"Parties agree that DSM shareholder incentive amounts shall be allocated to the rate classes in proportion to the net TRC benefits attributable to the respective rate classes."

What evidence is required to clear the DSMVA? (Issue 6.4)

"The utility shall clear DSMVA amounts, subject to review as a component of the DSM audit, to ensure compliance with the Board approved rules. The utility shall include the DSMVA as part of the audit described in issue 9.3. The utility may recover the amounts in the DSMVA from ratepayers provided it has achieved its annual TRC savings target on a pre-audited basis and the DSMVA funds were used to produce TRC savings in excess of that target on a pre-audited basis."

How should DSMVA balances be allocated between customer classes? (Issue 6.5)

"The Utilities shall allocate the DSMVA amounts in rates based on the Utility's DSM spending variance for that year versus budget, by customer class. The actual amount of the variance versus budget targeted to each customer class shall be allocated to that customer class for rate recovery purposes."

Should the DSM consultative be continued? If yes, (Issue 7.1)

"When required or useful, the utility will engage and seek advice from a variety of stakeholders and experts in the development and operation of its DSM program. As the utility is ultimately responsible and accountable for its actions, consultative activities shall be undertaken at its discretion. However, at a minimum, each utility will hold two consultative meetings annually. The purpose of the meetings will be to:

- Review annual results (the Evaluation Report will be sent to the Consultative annually for review) and select the Evaluation and Audit Committee ("EAC"). Three members will be selected using the current process used to select the Audit Sub-Committee; the fourth member will be the utility. In the current process, the members of the Consultative nominate individuals to stand on the committee. Then each member of the Consultative votes for the three members they would like on the committee. The three with the highest number of votes form the committee.

- Review the completed evaluation results.

The Utilities each acknowledge the principle that stakeholder consultation has proved valuable. They each intend to continue to take advantage of the input of the consultative as long as the consultative is adding value and the overall cost of the process is reasonable."

What role should the Consultative have in the DSM planning, design, approval and audit process? (Issue 7.2)

Settlement on this issue was referred to completely settled Issue 7.1.

How often should the Consultative and LDCs meet? (Issue 7.3)

"A utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement, subject to the requirement to meet twice annually set out under Issue 7.1 above. See Issue 7.5."

What is the appropriate amount that should be budgeted for Consultative and Sub-committee expenses? (Issue 7.4)

"The utility shall determine as part of the planning process, the appropriate amount to include in its overall DSM budget for stakeholder engagement, based on anticipated needs."

How should participation in the Consultative committee be determined? (Issue 7.5)

"The utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement. All intervenors in the Utility's most recent rate case shall be entitled to participate in the consultative meetings described in issue 7.1 above."

Should a percentage of the DSM budget be allocated to research? If yes, (Issue 8.1)

"Parties agree that the Utilities should conduct forward-looking DSM research. The appropriate level of budgets for research shall be determined by each Utility from time to time (depending upon need, market conditions, etc.) and each Utility should include a summary of its forecasted research in its multi-year DSM plan filed with the Board."

How should it be determined that research is required and when? (Issue 8.2)

"The utility shall determine the research needed to inform program assessment as part of its ongoing operational responsibilities and to ensure the long term viability of its DSM program. In making this

determination, the Utility shall give due consideration to any recommendations of the EAC, the Auditor, and the consultative."

To reduce duplication, should certain research commitments be combined for both LDCs? (Issue 8.3)

"Each Utility shall be responsible and accountable for its research activities and expenses. The utility is expected to seek and leverage efforts with third parties where appropriate but it is recognized that unique circumstances and objectives may exist that preclude partnering in some instances."

How often should a DSM market potential study be conducted by the LDCs? (Issue 8.4)

"Market potential studies, or updates to an existing study, must be filed by each Utility together with its multi-year plan. The Utility may, in its discretion, do additional studies of market potential or updates during its plan."

What is the purpose of evaluation reports and what should they contain? (Issue 9.1)

"EGD and Union are accountable to the Board to develop and implement cost effective DSM programs including the monitoring and evaluation of results. In order to inform stakeholders on the activities and results of the DSM programs undertaken, the utility shall file annually, a clear and concise Evaluation Report that summarizes the savings achieved, budget spent and the evaluations conducted in support of those numbers.

It is the purpose of the evaluation and audit process to review all input assumptions related to the delivery of DSM over the period of the multi-year plan. To assist with that purpose, the parties propose the establishment of an EAC to engage stakeholders in the development of an

evaluation plan and budget and to engage stakeholders in a review of the evaluation results as they become available over the term of the plan."

Is a third party audit of the evaluation report required? And if required, what should be the audit principles, scope and timeline? (Issue 9.3)

"The parties agree that a third party audit of the Evaluation Report is required. The auditor will be retained by the utility who determines the scope of the audit. It will be the role of the auditor to:

- Provide an opinion on the DSMVA, SSM and LRAM amounts proposed and any amendment thereto
- Verify the financial results in the Evaluation Report to the extent necessary to give that opinion
- Review the reasonableness of any input assumptions material to the provision of that opinion
- Recommend any forward looking evaluation work to be considered

The auditor shall be expected to take such actions by way of investigation, verification or otherwise as are necessary for the auditor to form their opinion. The auditor, although hired by the utility, must be independent and must ultimately serve to protect the interests of stakeholders."

Should there be an Audit Sub-committee with intervenor participation? And if yes, what role should the Audit Sub-committee have? (Issue 9.4)

"As described in Issue 9.3 above, parties agree that there should be an audit subcommittee entitled EAC. Participation in the EAC will be determined as set out in Issue 7.1.

The EAC will provide formal input into the evaluation plan. In regards to evaluation activities the EAC will continue to have an advisory role in the following:

- Consultation prior to the filing of the DSM plan on evaluation priorities for the next three years (or the duration of the multi-year plan). The utilities will, as part of their implementation plan, review all of the input assumptions over the course of each multi-year plan.
- Review and comment on evaluation study designs. Input on the research methodology used to determine the input assumptions.
- Reviewing the scope and results of evaluation work completed on new programs introduced over the course of the multi-year plan.
- Selection of the independent auditor to audit the Evaluation Report and determine the scope of the audit. The EAC will ensure that all comments on the Evaluation Report from the Consultative are reviewed by the auditor.
- Following the audit, review of the Evaluation Plan annually to confirm scope and priority of identified evaluation projects.
- The EAC will be responsible for meeting the reporting guidelines of the Board (found at Section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities). The EAC will provide a final report within 10 weeks from the later of, the receipt of the Evaluation Report and supporting evaluation studies from the Utility, or the hiring of the auditor. Recommendations of the EAC with respect to DSMVA, LRAM and SSM clearances shall be included in the EAC's final report. The EAC shall not consider any further information subsequent to the Board's filing deadline each year."

What characteristics are required to determine that a program is either a market transformation or lost opportunity program? (Issue 10.1)

"Market Transformation programs are those that (a) seek to make a permanent change in the market for a particular measure, (b) are not

necessarily measured by number of participants and (c) have a long term horizon.

Lost Opportunity programs are those that focus on DSM opportunities that will not be available, or will be substantially more expensive to implement, in a subsequent planning period."

How should it be determined that utility has achieved any prescribed target? (Issue 10.3)

and

What should be the length of a market transformation and lost opportunity program? (Issue 10.5)

and

What is the appropriate level of funding for a market transformation or lost opportunity program? (Issue 10.6)

Settlement on these issues was referred to completely settled Issue 10.7.

How should a program incorporate the following elements; information and education activities; incentives; research; activities to reduce market barriers such as building codes and energy efficiency appliance standards; and coordination with other entities (e.g. OPA)? (Issue 10.7)

"For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals."

Is it appropriate to use DSM funds for fuel switching to natural gas? (Issue 14.1)

> "Fuel switching is an important activity that can help alleviate some of the electricity supply programs faced by the province; however, the utility shall not use DSM funding to promote fuel switching to natural gas. The utility will pursue fuel switching activities as part of its marketing efforts that will be included in its rate case or other suitable application."

Is it appropriate to use DSM funds for fuel switching away from natural gas? (Issue 14.2)

> "Where fuel switching away from natural gas aligns with the Utility's DSM objectives the Utility may pursue these activities."

CHAPTER 3- PARTIAL SETTLEMENT (FINANCIAL PACKAGE)

In addition to the completely settled issues, the Board was presented with a list of partially settled issues. Union, EGD, CCC, SEC, Energy Probe, IGUA, LPMA, and VECC (the "Partial Settlement Proponents") were parties to a complete agreement on a number of issues. Certain of these issues were presented as a package (the "Financial Package") which the parties presented as being un-severable; i.e. if the Board did not accept the entire package, the Financial Package agreement would be withdrawn. The Financial Package dealt with:

- DSM budgets (Issue 1.3),
- DSM plan targets (Issue 1.4),
- allocation of DSM budgets amongst customer classes (Issue 1.7),
- the DSM incentive mechanism (Issue 5.2),
- the DSM variance account (Issues 6.1, 6.2, 6.3),
- market transformation and lost opportunity program budgets and utility incentives related to them (Issues 10.2, 10.4, 10.8), and
- targeted programs for low income customers (Issues 13.1, 13.2, 13.3).

The Partial Settlement Proponents explained that the individual elements of the Financial Package were tied together, and that to change one element would have repercussions on other elements. On the opening day of the hearing, the Board explained to the parties that it would hear whatever evidence the parties chose to lead; however, if at the conclusion of the hearing the Board determined that it did not wish to accept the Financial Package in its entirety, it would not re-open the hearing to hear fresh evidence on any of the issues. The Partial Settlement Proponents subsequently informed the Board that they would continue to exclusively support the Financial Package, and would not present any evidence to be considered in the event that the Board did not accept the entire Financial Package.

In addition to the Financial Package, the Partial Settlement Proponents reached a partial settlement on a number of other issues that could be considered individually. This chapter deals only with the Financial Package; the remaining partially settled issues will be addressed in Chapter 4.

The chief proponents of the Financial Package in the hearing were the utilities through their witness panels. The other Partial Settlement Proponents did not present witnesses in support of the Financial Package, but did conduct what was described as "friendly" examinations of the utility witnesses on these issues. The parties opposed to the Financial Package cross-examined the utility witnesses and, in some cases, filed their own proposals.

The Board will accept the Financial Package as presented by the Partial Settlement Proponents. As the Board explained when considering the meaning of a partial settlement on July 10, the Board has considered all of the issues in the Financial Package on an issue by issue basis. Taken individually and as a whole, the Board finds all of the proposals contained in the Financial Package to be reasonable.

The Board is pleased that the Financial Package amounts to what is largely a "rules-based" approach. Many of the major elements of the three year DSM plans will essentially be locked in for the term of the plan, and will not require further review by the Board during this period. This should result in significant regulatory savings for the parties, the Board, and, ultimately, for ratepayers.

The Board finds that the Financial Package strikes an appropriate balance between advancing DSM forward through higher budgets and ultimately higher TRC savings targets, while not forcing the utilities to try to spend money that they indicated they would have trouble spending in a cost effective manner. The Board is also satisfied that the Financial Package will not cause undue rate

impacts to ratepayers given the relatively modest nature of the proposals, in light of the overall revenue requirement of the respective utilities.

In addition to the overall comments above, the Board has the following remarks on the individual issues that comprise the Financial Package.

How should the financial budget be determined? (Issue 1.3)

The Partial Settlement makes the following proposal.

> "Parties in agreement with this partial settlement accept that a DSM budget cap should be developed using the following formulaic approach in each year of a multi-year DSM plan. For the first year, the budget for EGD will be $22.0 million, an increase of $3.1 million or approximately 16% from its 2006 budget. For Union, the 2007 budget will be $17.0 million an increase of $3.1 million or approximately 22% from its 2006 budget.
>
> In the second and subsequent years of a multi-year DSM plan, the DSM budget for each year of the plan will be determined by applying an escalation factor of 5.0% for EGD and 10% for Union to the budget developed for the immediately preceding year. The purpose of the application of different escalation factors for EGD and Union is to address the desire by some parties that the difference between the level of spending by EGD and Union be narrowed. The parties agree that this formula results in budgets of $23.1 million and $24.3 million for EGD in 2008 and 2009 respectively, and budgets of $18.7 million and $20.6 million for Union in 2008 and 2009 respectively.
>
> Parties to this partial settlement agree that the Utilities remain obligated to develop, and spend monies on, cost-effective DSM programs up to the budget amount developed by this methodology."

The Board is satisfied that the Financial Package proposal reaches an appropriate balance between increasing DSM budgets and approving budgets which can be spent in a cost effective manner. Both Pollution Probe and GEC argued in favour of much higher budgets; however, the Board is not convinced that the utilities could currently spend these amounts cost-effectively.

Should there be plan targets and if so, should they be volumetric or based on TRC values? (Issue 1.4)

The Financial Package agreement makes the following proposal:

> "Parties to this partial settlement further agree that there will be an annual TRC target. The parties agree to phase in a formula over the next three years which will set this target, as described below, by averaging the Utility's actual audited TRC results over the previous three years and applying to this figure an escalation factor equal to 1.5 times the amount by which the utility's budget is increased. The parties agree to phase in the aforementioned formula over the next three years beginning with an agreed upon target for each utility in 2007 which, for Union will be $188 million and for EGD $150 million.
>
> Furthermore, the parties agree that, in the event the avoided costs used by the utility are, at a later date, updated, the actual audited results from previous years used to calculate the target will be adjusted to reflect these updated avoided costs.
>
> Finally, and for greater certainty (and as an example), set out below is the formula by which the target will be set for Union, with 2010 provided for illustrative purposes only:
>
> • 2007 - $188 million.
>
> • 2008 - The simple average of $188 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

• 2009 - The simple average of $188 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

• 2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

For EGD, the formula by which the target will be set is as follows, with 2010 provided for illustrative purposes only:

• 2007 - $150 million

• 2008 - The simple average of $150 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

• 2009 - The simple average of $150 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

•2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie.7.5%).

The “actual audited TRC values” shall be the total TRC produced for the year in question as determined by the audit in the following year. In setting the target for 2009 and subsequent years, the actual audited TRC value for the immediately preceding year, but not for the prior two years used in the average, will be adjusted to reflect any changes in input assumptions determined in the audit to apply to that year for LRAM purposes. By way of example, if a free rider rate is increased in the 2009 audit carried out in the first half of 2010, under the partial settlement that change would normally apply to SSM for the years 2010 and thereafter, but to LRAM for 2009 as well. In calculating the target for 2010, the three year average will use the TRC values otherwise determined for 2007 and 2008, but for 2009 will use the audited TRC values, adjusted for that change in free rider rate identified in the audit.”

The Board is satisfied that the Financial Package proposal sets reasonable TRC targets for the utilities. The Board notes that the formula used to derive the targets in years two and three of the plan is self adjusting to account for actual performance in the previous year. The Board finds this formula to be preferable to setting the targets for all three years in advance.

The Board notes that the target for Union in year one of the plan will actually be lower than its Board approved target for 2006. The Board heard evidence from Union that the TRC target for 2006 had been set at a level that it will not attain. Union indicated that according to its current projections for 2006, the company will likely achieve TRC savings in the range of $170 million (on a target of $216 million). The Board accepts Union's evidence in this regard, and finds that a target of $188 million in year one of the three-year plan is reasonable.

On what basis should the DSM program spending be targeted amongst customer classes? (Issue 1.7)

The Financial Package agreement makes the following proposal:

> "Parties acknowledge that EGD's and Union's rate classes and customer needs are not identical, and hence it is not appropriate to restrict spending based on a rigid formulaic approach by rate class. The Utilities acknowledge and accept the principle that their portfolio of DSM programs should provide customers in all rate classes and sectors with equitable access to DSM program(s) to the extent reasonable, and that this principle must be balanced and consistent with the principle of optimizing cost-effective DSM opportunities. To the extent that a proposed multi-year plan proposes DSM sector (ie. residential, commercial, or industrial) level spending that is significantly different than the historical percentage levels of spending in those sectors, the utility will provide its explanation for this in its proposed multi-year plan. Parties may challenge any such

explanation, or its impacts. The Board will then determine whether to approve the revised spending ratios, and if so, under what conditions.

To the extent that actual sector level spending then varies significantly from the ratios identified in the plan, parties may challenge the appropriateness of the deviation from the plan when the utility seeks approval for the clearance of relevant accounts and the Board can make such order as is appropriate. (Issue 1.7)"

The Board is cognisant of the tension between ensuring that each rate class is allocated an appropriate portion of DSM funds on the one hand, and the benefits of targeting spending to the most cost effective programs regardless of what rate class they fall in on the other. The Board is satisfied that the Financial Package proposal finds the appropriate balance.

What is an appropriate incentive mechanism and how should it be calculated? (Issue 5.2)

The Financial Package agreement makes the following proposal:

"The parties to this agreement agree that an SSM shall be established for the first year of the plan and shall be in effect for each year of each multi-year plan.

Parties agree that the amount of any SSM shall not be included in the Utility's return on equity ("ROE") for the purposes of setting rates or in the calculation of any earnings sharing amounts.

The parties agree that for the purposes of this settlement, the TRC indexing target for 2007 for EGD will be $150 million, and for Union, $188 million. Targets for subsequent years shall be set in accordance with the formula in Issue 1.4. The cumulative SSM incentive payment to each utility for achieving their respective TRC target will be set by a formula,

and at 100% of TRC target will be $4.75 million. For the purposes of determining whether each utility has met its 100% TRC target, the input assumptions for the calculation of SSM will not be changed retroactively. For clarity, changes to input assumptions, which are confirmed through audit, apply in the year immediately following the year being audited. For example, input assumptions for purposes of the SSM remain fixed for 2007, and any changes to input assumptions which change as a result of the audit of the 2007 results which is undertaken in early/mid-2008 will apply from the beginning of the 2008 year forward. Also see Issue 3.3.

For both Utilities, the following formula applies for the determination of the SSM curve and resulting cumulative payout. The SSM payout will be calculated based on the results as they apply along the curve and each of the following percentage thresholds do not represent lump sum payments for reaching the threshold but simply serve to structure the SSM curve based on targets and SSM amounts as agreed to by the supporting parties:

Up to 25% of the annual target, a total payout of $225,000
Up to 50% of the annual target, a total payout of $675,000
Up to 75% of the annual target, a total payout of $2,250,000
Up to 100% of the annual target, a total payout of $4,750,000
Up to 125% of the annual target, a total payout of $7,250,000
In excess of 125% of the annual target, a total that is capped at no more than $8,500,000.

The parties agree that the annual ‘cap’ of $8.5 million will increase annually by the Ontario CPI as determined in October of the preceding year (i.e., the 2008 cap will increase based on CPI as determined at October of 2007).

See also issue 10.4 for the incentive available to the utilities in respect of market transformation programs”

During the hearing, the utilities provided the formula in calculating SSM, which is reproduced below:

> "For achievement of between 0 and up to 25.0% of the annual target, the SSM payout shall equal $900 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 25.0% up to 50% of the annual target, the SSM payout shall equal $225,000 plus $1,800 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 50.0% up to 75.0% of the annual target, the SSM payout shall equal $675,000 plus $6,300 for each 1/10 of 1% of target achieved above 50.0%, and
>
> For achievement of greater than 75.0% of the annual target, the SSM payout shall equal $2,250,000 plus $10,000 for each 1/10 of 1% of target achieved above 75.0% to a maximum of the SSM annual cap."

There was a complete settlement on issue 5.1, in which all parties agreed that there should be an incentive mechanism. The Financial Package proposal for issue 5.2 presents a formula for determining the exact amount of the SSM payout based on the level of success each utility has achieved in hitting its TRC targets. The Financial Package proposal calls for an escalating incentive scale which starts at the first dollar of TRC net benefits achieved. This proposal marks a change from the current Board approved practice where the utilities are required to reach a certain level of net TRC savings before any incentive is realized. The Board is satisfied that this change to the *status quo* is appropriate. The Board is persuaded by the utilities' evidence that the proposed structure is more likely to attract management attention to DSM programs. The Board is also comforted by the fact that the incentive payments for performance below 50% of the TRC target is very low. Further,

the $8.5 million cap on incentive payments for any one year ensures that ratepayers will not have to pay an undue amount if a utility achieves extraordinary success.

Demand Side Management Variance Account (Issues 6.1, 6.2, 6.3)

The Financial Package agreement makes the following proposals:

> "Parties agree that the DSMVA shall be continued. The DSMVA shall be used to "true-up" the variance between the spending estimate built into rates for the year and the actual spending in that year. If spending is less than what was built into rates, ratepayers shall be reimbursed. If more is spent than was built into rates, the utility shall be reimbursed up to a maximum of 15% of its DSM budget for the year. All additional funding must be utilized on incremental program expenses only (i.e. cannot be used for additional utility overheads). For greater certainty, program expenses include market transformation programs. "
>
> "There should be no limit on the amount of under spending from budget that should be returned to ratepayers. Parties agree that a Utility may spend and record in the DSMVA for reimbursement to the utility, in any one year, no more than 15% (fifteen per cent) of that Utility's DSM budget for that year. "

The Board finds the Financial Package proposal to be reasonable. The DSMVA will allow utilities to aggressively pursue programs which prove to be very successful, even where this causes them to exceed the Board approved budget (by up to 15%). It will also ensure that unspent DSM funds are returned to ratepayers.

Market Transformation (Issues 10.2, 10.4, 10.8)

The Financial Package agreement makes the following proposals:

> "Every utility DSM plan should include an emphasis on lost opportunity and market transformation programs and activities. For purposes of this agreement, parties agree that this emphasis will consist of a market transformation budget of $1.0 million per utility per year and is included in the total budget amounts referenced in issue 1.3."
>
> "Parties agree that each utility is entitled to an incentive payment of up to $0.5 million in each year of the multi-year plan based on the measured success of market transformation programs. The measurement and calculation methodologies to determine whether this amount has been earned in the year shall be detailed by each utility in its multi-year DSM plan. For clarity, this amount is in addition to any amount earned at issue 5.2. By way of example, a Utility may propose in its DSM plan a program to increase the market share of a particular high efficiency product, and a $250,000 annual incentive based on the market share of that product at the end of each year, measured by a specific third party market index, being 10% higher than the previous year. If the DSM plan is approved by the Board including that program, the Utility will be entitled to a $250,000 incentive in each year that it meets the stated market share goal."
>
> "For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals."

The Board is satisfied with the Financial Package proposal for market transformation. GEC argued for a much larger budget for market transformation and lost opportunity projects. Utility witnesses stated that the utilities could not effectively spend these budgets. The Board notes that the proposal regarding utility incentives for these programs does not achieve the level of certainty that exists for other elements of the Financial Package. While GEC argued for a more concrete incentive mechanism, the witnesses at the hearing were largely in agreement that market transformation programs are not necessarily amenable to fixed and inflexible rules. The Board agrees. The Board therefore accepts the proposal as filed.

Targeted Programs (Issues 13.1, 13.2, 13.3)

The Financial Package agreement makes the following proposals:

> "Parties to this settlement accept that low-income customers face barriers to access DSM programs which are unique to this group of customers. Accordingly, parties to this settlement agree that it is appropriate to establish a minimum amount of spending on targeted low-income customer programs in the residential rate classes of both Utilities. It is agreed that each utility will spend out of its DSM budget a minimum of $1.3 million, or 14% of each respective utility's residential DSM program budget, whichever is greater. For clarity, a utility may expend more than $1.3 million or 14% of its residential DSM program budget if the utility considers it appropriate. The Utilities each agree to increase the $1.3 million spending floor by the budget escalation factor appropriate for the utility (i.e. EGD 5%; Union 10%) in each of the second and third years of a three year plan.
>
> The parties to this settlement further agree that of the $1.0 million budget for market transformation programs, each utility will expend no less than 14% on targeted low-income market transformation programs.

> The Utilities agree that by the establishment of this spending level floor, they will not, as a result, reduce planned DSM spending in other rate classes or sectors which are directed at low-income residents (e.g. social housing multi-unit residential spending) or their spending on fuel switching targeted to low-income customers."
>
> "Each of the utilities is at liberty to develop appropriate eligibility criteria for low income residential programs, and each utility agrees to consult with VECC in respect of the development of eligibility criteria and low-income program parameters. Parties to this settlement generally accept that criteria presently used by various levels of government for the purposes of determining low income eligibility may be appropriate for use by the utilities."

The only customer segment proposed to the Board for targeted programs were those for low-income customers. The Board finds the Financial Package proposal to be reasonable. The proposed spending floor should ensure that low-income consumers have access to DSM programs at least in approximate proportion to their percentage of residential revenue. LIEN argued that spending on low-income DSM programs should be equal to 18% of the total residential class DSM budget, assuming the total DSM budget is split proportionately amongst all rate classes. Under Issue 1.7, the Board has already stated its acceptance of budget allocations that are not strictly proportional to customer class revenue. There was conflicting evidence in the hearing as to the estimated proportion of low-income households within the residential sector. LIEN argued that the proportion was 18% while the Partial Settlement proponents argued that 14% was closer to the actual proportion. The Board finds LIEN's evidence on this matter unconvincing and finds that 14% is supported by the evidence. The Board, therefore, accepts the proposal that each utility will annually spend 14% of the residential DSM budget or $1.3 million on low-income programs, whichever amount is greater.

CHAPTER 4 - REMAINING NON-SETTLED ISSUES

The previous chapter, Chapter 3, dealt with the settled issues and the partially settled issues that were presented to the Board as a "financial package". The following chapter, Chapter 5, includes discussion of Issue 3.2 relating to the question of whether there should be a common guide. This chapter, Chapter 4, deals with the remaining non-settled issues that were addressed during the oral hearing.

What should be the timing of the schedule for submitting and reviewing Demand Side Management ("DSM") plans? (Issue 1.1)

The Board was presented with a partial settlement. All intervenors agreed as follows:

> "…DSM plans should be filed at least nine months prior to the plan period to which they relate, to give sufficient time for stakeholders and the Board to consider them, and for Board approval prior to the plan period commencing."

The utilities believe that filing the DSM plans four months in advance of the initial plan year will allow sufficient time to have the plan in place by the beginning of the following year. The utilities indicated that this would allow them to file final results from the previous year's audit, rather than interim un-audited results.

For clarity, the timing issue here relates to future DSM plans. The timing of filing for the inaugural three-year plan is dealt with elsewhere in this decision.

The Board notes that a filing date at least nine months in advance would entail the presentation of un-audited performance of the plan's second year. This may likely involve updates once the results are audited. The Board is of the view that updates should be avoided where possible, as they are generally not conducive

to an efficient review. While the Board anticipates that a four month time frame will likely be adequate to accomplish the review given the rules approach adopted by the Board, there is the possibility that it will not. In that case, the consequence is a start date that may not immediately follow the last day of the previous term of the plan. While this may not be desirable, it would be of little adverse consequence as the previous plan would continue. It is in the Board's view a reasonable risk to take in order to obtain the benefits of an efficient review. The Board therefore accepts the utilities' proposals that subsequent plans be filed four months in advance of their commencement.

What process and rules should be available to amend the DSM plan? (Issue 1.5)

There was no settlement (complete or partial) on this issue.

In a response to an undertaking (J2.2), the utilities referenced the preamble of the Partial Settlement which reads

> "For greater clarity, where any settled issue is expressed to continue throughout a multi-year plan, no party to that settlement may seek to re-open that issue with respect to either Utility in any other proceeding prior to the earlier of a) the Board's consideration of the multi-year plan of that Utility, or b) a further hearing on DSM in which the Board has determined that such issue is to be considered "

and stated that

> "… it is the position of the utilities that the Board should amend a multi-year plan during the currency of that plan only in exceptional circumstances. It is expected that with the proposed language, all stakeholders will recognize that any application for an amendment must meet a very high onus to demonstrate undue harm. The intent of the above section is not to provide parties with an opportunity to reopen the framework rules established in this proceeding."

As noted at the oral hearing, no rule can prevent requests for review, or should for that matter. It would not be in the public interest to disallow re-opening of the plan in midstream under any circumstances. At the same time, the purpose of this generic initiative is to avoid unnecessary re-visitation of DSM issues.

Demonstration of "undue harm" was accepted as a reasonable principle by intervenors. The Board concurs that it is a workable principle and useful in the circumstances. There was also support for the proposal by SEC that any party claiming undue harm must first seek leave of the Board before the matter is thoroughly reviewed, and leave should be given only in exceptional circumstances. The Board notes that if a proposed amendment came forward either by way of a motion or by way of application, the Board has the authority and tools to subject the request to the appropriate scrutiny, and to ensure that the intentions of the parties and the Board are respected.

As for the proposal by the utilities that the Board use its cost assessment powers as a further measure to dissuade frivolous requests, this option is always available to the Board and can be used when warranted. This applies equally to intervenors and the utilities.

Should a TRC threshold be established to determine if a measure and/or program is cost effective or should it be based on the cost effectiveness of the portfolio? If so, what should the value be? (Issue 2.2)

The Board was presented with a partial settlement. All parties except SEC agreed as follows:

"The general principle is that all measures and programs should exceed a benefit to cost ratio of 1.0 to be included in the portfolio, but exceptions are reasonable where other benefits are apparent (e.g., pilot programs)."

SEC argued for a screen value of 1.2 rather than 1.0 on the basis that TRC is based on assumptions that change, so it would be appropriate to build in a margin to ensure feasibility. SEC noted that nothing is lost since it appears that

there is much more DSM available than the utilities can handle and thus, instituting a higher threshold programs would be better. SEC noted that the exception related to the screen value for pilot programs would still exist.

In the Board's view, the availability of DSM initiatives that exceed the 1.0 cost-benefit ratio is not a compelling argument for deviating from a widely-practiced threshold of 1.0. A program that yields a benefit cost ratio over 1.0 does provide positive net benefits and it would not be appropriate to knowingly forego such benefits. As for SEC's argument that a higher threshold would avoid the risk of uneconomic programs, this can be addressed by instituting more robust input assumptions. Moreover, the risk of uneconomic programs is offset by the fact that, from a societal perspective, the TRC test does not reflect the positive aspects of mitigating negative externalities that are inherent in gas consuming activities. In fact the risk of undertaking uneconomic programs is self-correcting by the incentive by the utilities to maximize rewards by maximizing TRC benefits. For the above reasons, the Board does not accept SEC's suggestion.

However, the Board notes that the partial settlement refers to pilot programs as an example of programs where an exception to the threshold of 1.0 may be permitted. The implication is that there may be other types of programs. No other examples were provided. The Board prefers more certainty as to the exceptions in these circumstances. The Board therefore finds that the exception to the TRC threshold should be restricted to pilot programs at this time.

How often should avoided gas costs be calculated and should the Local Distribution Companies ("LDCs") use identical avoided costs? (Issue 3.5)

There was no settlement (complete or partial) on this issue.

EGD undertook to explore if the utilities could produce a common set of avoided costs and responded (J2.4) as follows:

> "Each Utility will calculate avoided costs for natural gas, electricity and water that reflect the cost structure and service territory of the Utility. In order to ensure consistency, a common methodology will be used to determine the costs. The Utilities will coordinate the timing for selecting commodity costs so that they are comparable.
>
> The avoided costs will be submitted for review as part of the multi-year plan filing and should be in place for the duration of the plan. The commodity portion of the avoided costs will be updated annually.
>
> As avoided costs are long term projections, updating the costs, other than the commodity costs, on a three year cycle should not cause benefits to be significantly under or overstated. Regardless of how often the avoided costs are updated, the same avoided costs will be used to calculate both the target (relative to 2007) and incentive amount, therefore it is anticipated that the relative impact would be minimal."

Only GEC argued against the utilities' proposal. It argued that the utilities should use common values for gas commodity, electricity and water. With respect to the avoided distribution system costs (e.g. pipes and storage etc.) which may vary by utility, GEC submitted that the utilities should be required to demonstrate how different these values are so that the Board can determine whether or not the difference is material.

The Board does not accept GEC's proposals. Avoided gas costs are a significant component of calculating TRC benefits. Gas costs can be different for each utility depending on, among other things, its gas supply management policies and practices.

With respect to system costs, these are certainly unique to each utility and they too are an important part of the TRC benefit calculation. The benefits of

estimating and measuring with more precision the TRC values for DSM programs outweigh, in the Board's view, the costs of the incremental effort to determine and review the different values for gas commodity and system costs.

The Board also notes that the methodology for estimating the values for natural gas commodity, system costs, electricity and water will be common for the two utilities, which will ensure some measure of consistency and efficiency.

The Board accepts the utilities' proposals.

Should the LDCs be entitled to revenue protection? (Issue 4.1)

The Board was presented with a partial settlement on this issue. All parties except CME agreed that the utilities should be entitled to revenue protection.

By accepting the "financial package" settled issues earlier in this decision, the Board has not found merit in CME's argument that the utilities should not be entitled to revenue protection. As long as a utility's fixed costs are not fully recovered through fixed charges (and part of the fixed costs are therefore being recovered through the variable charges), there is an inherent conflict for the utility between sales growth and conservation. The existence of a mechanism to neutralize this conflict through an LRAM mechanism is therefore essential to the success of DSM.

What is the appropriate level of funds that should be budgeted for an evaluation report and audit? (Issue 9.2)

The Board was presented with a partial settlement on this issue. All parties except GEC agreed as follows:

"The Utilities shall ensure that DSM budgets and spending include adequate funding to complete the required annual evaluation and audit activities. The utility is responsible and accountable to ensure that evaluation and auditing activities are concluded in a timely fashion and that the associated costs are reasonable."

GEC argued that 3% of the DSM budget should be allocated to evaluation and audit over the three year period. GEC noted that the utility should have the flexibility to move spending between years to balance the lumpiness of spending. GEC noted that this budget should only be spent if required.

The Board fails to see the rationale or benefit of GEC's suggestion. In fact the Board only sees lost DSM program opportunities as the utilities will not be able to access any unspent portion of a fixed budget reserved for evaluation and audit. The Board does not accept GEC's proposal. The utilities should be spending in evaluation and audit as required and as prudent.

What attribution rules or principles should be applied to jointly delivered DSM programs? (Issue 11.1)

There was no settlement (complete or partial) on this issue.

The issue for the parties was how the framework rules will deal with situations where a utility operates or participates in a program with a non-rate-regulated third party and, where this occurs, how should the determination of the TRC benefits be made. For completeness, the Board also makes a finding on attribution between Board rate-regulated parties.

The utilities advocated the centrality principle, as decided by the Board in EGD's EB-2005-0001 rate case. Under the centrality principle, it would be considered that the utility played a central role if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. In such circumstances the utility would be entitled to 100% of the TRC benefits.

Where the utility's role is not considered central, the utilities differed. EGD advocated a scaled role approach, whereas Union proposed that the attribution of TRC benefits would be measured by free ridership. In Union's view, there is

no material distinction in the two approaches as both would likely produce the same result. The utilities agreed that it should be the same arrangement for both as determined by the Board.

In the view of CCC and GEC, the rule of centrality is not particularly helpful at avoiding the need to analyze each project or proposal.

The Board notes that the utilities did not dispute the suggestion that attribution of benefits for jointly delivered DSM programs must be done on a case-by-case basis. The Board agrees that this is a reasonable approach. The issue is whether the centrality principle should be maintained.

The Board recognizes that it accepted the centrality principle in the EB-2005-0001 rate case when it dealt with EGD's EnerGuide for Houses program. What makes the re-assessment necessary is the fact that this is a generic hearing for the gas distributors and it is appropriate to review the rules *de novo*. In that regard, the Board notes that, pursuant to the settled and approved issues, there is now a delineated role for the evaluation and audit committee in respect of programs pursuant to the settlement agreement and the Board's acceptance of the agreement. Specifically, the attribution rules set by the Board will be used by the evaluation and audit committee to assess and settle the TRC savings attributable to the utility's role, which will ultimately be reviewed by the Board.

As the utilities concede, the centrality rule is not absolute. There can be considerable judgment in determining whether or not the role of the utility is central in a particular program. Attribution on the basis of the utility's participation that is considered incremental to the program on the other hand appears to remove some of the controversy, and it does not preclude full 100% attribution to the utility. However, a drawback is that the incrementality approach may not adequately and fairly capture situations where a program would not have existed at all if it were not for the utilities.

On balance, the Board accepts the centrality principle for purposes of the first multi-year DSM plans, under which the utility would be entitled to 100% of the TRC benefits if it can be demonstrated that it has a central role in a program. That is, as the utilities proposed, if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. The experience to be gained over the next three years will inform as to the suitability of continuing with this approach after that point.

This leaves the difference in approach by the two utilities where centrality is not claimed or demonstrated.

The Board accepts the utilities' position that the distinction between their approaches is without a difference. The utilities' differences reflect different internal practices, as noted by the utilities. The utilities acknowledge that either approach would involve the evaluation of attribution of each program by the evaluation and audit committee, and ultimately by the Board. However the utilities accept that there should only be one common approach, to be determined by the Board.

The Board prefers the free ridership approach advocated by Union as this would be more consistent with the general approach for measuring TRC benefits in other DSM activities implemented by the utilities.

The TRC benefits for program partnerships with Board rate-regulated entities (e.g. electricity distributors) shall be allocated in the manner indicated in the electric TRC Guide, as was canvassed at the oral hearing. That is, a gas distributor partnering with an electricity distributor shall claim all of the benefits associated with the gas savings.

How should existing or future carbon dioxide offset credits be dealt with in DSM plans and programs, if at all? (Issue 11.2)

The Board was presented with a partial agreement on this issue. All intervenors agreed as follows:

> "Until the rules are known, a deferral account should be established for each Utility and any dollar amounts representing proceeds from the sale or other dealings in credits should be credited to that account".

The utilities submitted that until the rules of carbon dioxide offset credits are known, the Board should not make any determination on this issue.

The Board accepts the argument by certain intervenors that there is no harm in ordering a deferral account to capture any future carbon dioxide offset credits. While the matter could wait until the resolution, if any, of the carbon dioxide offset credits matter, the utilities did not present convincing arguments to counter the no harm proposition advanced by many intervenors. The Board is generally reluctant to authorize the establishment of deferral accounts without a more concrete and immediate need. However since this matter is within the scope of DSM, there is an opportunity to deal with it now without the need for further processes. Therefore the Board concludes that the establishment of a deferral account would be a reasonable approach in the circumstances, and so orders.

Should free riders for custom projects be determined on a portfolio average or on a project basis? (Issue 12.1)

There was no settlement (complete or partial) on this issue.

The utilities proposed that the free ridership rate should be determined on a portfolio average basis. The single free ridership rate would apply across a number of technologies and a number of sectors. The utilities proposed a free ridership rate of 30%.

VECC submitted that although the fairest way to address attribution for custom projects would be on a project-by-project basis, a portfolio average approach can be acceptable for administrative efficiency, but with the conditions that there should be emphasis on sector-by-sector as suggested by LPMA.

The Board sees merit in the notion of differentiated free ridership rates by market segment, at least for large and small enterprises. However, this is a significant undertaking. The utilities revealed that at present there are over one thousand custom projects within EGD and a fifth of that within Union. A segmentation analysis would need to be done on a sample basis, statistically justified, and reviewed by the parties and the Board. Ordering such studies for the two utilities for this plan may jeopardize the timetable of filing and implementing the respective DSM plans. The Board also notes the testimony by Union's witness that any differences in free ridership rates through market segmentation may at the end balance out and in fact support a single rate.

For these reasons the Board accepts a portfolio average approach for custom projects. The free ridership rate for custom projects will be determined as part of the process that will determine the input assumptions.

For the next generation multi-year plans, the Board expects the utilities to propose common free ridership rates for custom projects that are differentiated appropriately by market segment and technologies.

Should custom projects have a third party or an internal audit and if so, what would be the audit scope and process of the audit? (Issue 12.2)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Custom projects should be audited using the same principles as any other programs. Audit activities should be sufficient for the auditor to form

an opinion on the overall SSM, LRAM and DSMVA amounts proposed in the Evaluation Report."

EGD proposed that the custom projects be audited as part of its portfolio results based on a significantly appropriate representative sample. The auditor would then confirm the results and these would be included for the purposes of calculating SSM and LRAM, consistent with the completely settled Issue 3.3.

Union proposed that, as custom projects form a large part of Union's DSM portfolio, they should be assessed by a third party, and noted that this is in fact Union's current practice. Union explained that a statistically significant sample of both the largest and smallest subset of projects should be evaluated by a third party evaluator, hired by the utility. The evaluator would not be the auditor because of the particular technical expertise required to review custom projects. The report of the technical expert would form part of the evaluation report, which would be forwarded to the auditor.

The Board notes that the distinction between the Union and EGD proposals is that, in Union's case, the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor. In EGD's case, that first cut is done in-house but EGD still engages a third party to do an evaluation of the sampling of its custom projects. Although in both cases the results would be forwarded to the auditor for review, the Board is of the view that a common approach should be adopted for the two utilities. The Board prefers Union's current practice where the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor.

Union proposed the adoption of the rule in the TRC handbook for electric CDM, where the projects selected for assessment should consist of a random selection of 10% of the large custom projects representing at least 10% of the total volume

savings for all custom projects and consist of a minimum number of five projects. The Board adopts this proposal, which shall apply to both utilities.

[With respect to custom projects], how should savings be determined and what documentation is required? (Issue 12.3)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life, so for example should include a factor for the possibility that a measure will not be used for its entire engineering life (due to bankruptcy, change in operations, etc.)."

During the hearing, a complete settlement was considered to have been reached by all parties by truncating the text as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life."

The Board concurs with the settlement.

[With respect to custom projects], should the volumetric savings recorded be actual or forecasted volumes and what documentation is required to verify this result? (Issue 12.4)

In the Partial Settlement, parties referred this issue to Issue 12.3, which in turn was considered to have settled by the parties during the hearing.

The Board approves this settlement.

[With respect to custom projects], how will an appropriate base case be determined? (Issue 12.5)

The Board was presented with a partial settlement on this issue. All intervenors and Union agreed as follows:

> "Only the part of the project that the Utility influenced is to be counted for SSM or LRAM purposes."

The Board notes that only EGD opted out on the basis that it does not know the implications of the word "influence". The Board is not in a position to provide assistance to EGD in this regard as EGD itself was not clear as to the relief that it is seeking. However, the Board's findings in this decision taken in their entirety should help alleviate EGD's concerns. In particular, the Board does not see how the proposed wording would invalidate settled Issue 3.3, which is EGD's stated concern.

The Board accepts the partial settlement on this issue.

How should the funding levels and targets, if any, for the gas utilities' electricity to natural gas fuel switching programs be determined? (Issue 14.3)

The Board was presented with a partial settlement on this issue. All intervenors agreed as follows:

> "Programs promoting fuel switching to natural gas, which should be funded from the marketing budget of the Utility, should, just as with DSM programs, seek to balance maximization of TRC benefits with minimization of rate impacts."

Union noted that that all parties agreed that fuel-switching to natural gas is not a DSM activity (and DSM funds should not be used for this purpose) and fuel-switching away from natural gas may be appropriate in certain circumstances and may therefore constitute DSM. Union stated that it is simply seeking

guidance from the Board or approval to bring an application in the future which will address the issue of the appropriate level of funding, as well as the target, if any, associated with fuel-switching, and thus how success ought to be measured.

EGD submitted that in accepting the completely settled issues in this matter, the Board has effectively deferred the issue to a future panel of the Board that will consider it in the context of whatever proceeding any fuel-switching budget is brought forward.

In this Board Panel's view, making findings, providing guidance or even commenting on the substantive matters of fuel switching would not be appropriate. In making this finding, the Panel was mindful of the impact any conclusions may have on a future panel of the Board. Equally important, there was an insufficient evidentiary basis in this proceeding for the consideration of limiting fuel-switching to a TRC test only. Parties that believe that a TRC test should be used for a fuel-switching budget will have the opportunity to raise this issue in future rate proceedings.

What is the appropriate role of gas utilities in electric CDM? (Issue 15.1)

There was no settlement (complete or partial) on this issue.

EGD submitted that it would like to have the flexibility to make its expertise in DSM available in the electric Conservation and Demand Management (CDM) arena. It also stated that it was not planning to engage in CDM consulting. Union stated that it does not plan to engage in electric CDM. However, Union supported EGD's submissions.

SEC stated that on the assumption that the utilities can engage in electric CDM activities under the Undertakings given to the Lieutenant Governor in Council (the "Undertakings"), it supported the idea that the gas utilities be able to do joint

programs with the electric LDCs, as this would tend to lower costs for the gas utilities. SEC cautioned against diverting the gas utilities' attention from gas DSM programs to electric CDM since the latter is, in SEC's view, more lucrative. CCC noted that there is no like thinking by the two utilities on their role regarding DSM activities and that there is no necessary and rational connection between electricity CDM and the utility DSM programs; therefore, there is a need to impose some constraints on the utilities' activities. CCC also questioned the legality of the gas utilities engaging in these activities without proper dispensation under the Undertakings. GEC submitted that gas utilities should only engage in electric CDM when it enhances gas DSM; otherwise, it would be a competing demand on scarce resources and a distraction from their primary focus. VECC supported co-delivery of DSM and CDM measures as it would reduce program costs, but not on the basis of incremental costing and profit sharing. LPMA and VECC suggested that electric CDM should be considered a non-utility activity for revenue requirement purposes of the distribution business.

EGD responded that it does not need an order or dispensation from the Board to engage in electric DSM. It specifically noted that gas DSM itself already generates electricity TRC savings which are included in the SSM calculations. EGD also stated that CDM is consistent with the objectives set out in the Ontario Energy Board Act to promote energy conservation; the Act does not limit the objective to simply natural gas. Further, this matter was canvassed in the EGD's EB-2005-0001 rate case where the Board approved the 50/50 earnings sharing mechanism for the joint participation in the TAPS electric CDM program.

The Board considers that the regulatory construct in Ontario is the concept of a pure distribution utility. This is manifested in the Undertakings and in the Board's rulings for some time. Gas DSM has remained an activity within the corporate structure of the utility and there is no compelling reason to alter this at this time - neither the utilities nor the intervenors instigated or sought a change with respect to gas DSM.

Recent developments in electric CDM may likely bring opportunities for gas utilities to engage or enhance engagement in this area. EGD has some minor engagements with Toronto Hydro Electric Systems Limited ("THESL"). Union does not appear to have any immediate plans to enter the electric CDM field. EGD, however, is interested in possibly expanding its electric CDM role where it is appropriate to do so.

There appears to be strong support if not consensus that the gas utilities should be permitted to engage in electric CDM if such engagement brings about cost efficiencies and the clear focus of the utility's demand management activities should relate to gas. The concern that attention may be diverted from gas DSM to electric CDM is, in the Board's view, theoretical at this stage. It is not axiomatic that enhanced engagement in electric CDM by the gas utilities will necessarily result in lost opportunities for gas DSM. The two initiatives can co-exist in an optimal and workable fashion. This is especially the case where demand management involves funding initiatives, not infrastructure, which has been the experience thus far.

The Board therefore is not concerned about the gas utilities in their present corporate structure engaging in electric CDM as long as such activities can be reasonably viewed as complementary and ancillary to gas DSM and do not involve investments in infrastructure. An example of that is EGD's involvement with THESL in the TAPS program. In fact, the utilization of the demand management expertise residing in the gas utilities should be viewed positively from a public interest perspective given the well known challenges in the Province's electricity sector. In that regard, engagement by the gas utilities in programs aimed at switching from electricity to gas is encouraged.

The concern arises if the gas utilities undertake stand-alone electric CDM activities. That is, programs that are not or do not appear to be synergetic to or enhancing gas DSM, especially if they involved investments in infrastructure on account of electric CDM. This would alter the regulatory construct of a gas distribution utility which would necessitate a review under the Undertakings and the Board's regulatory policies.

The Board is hampered in its assessment of the appropriate role for gas utilities in these situations. The Board is concerned about granting what might be viewed as blanket approval for the utilities to engage in electric CDM activities without knowing exactly what types of activity this might entail. For example, it is not clear if the gas utilities would bid for participation in the recently announced $400 million in OPA funding for electric CDM programs. As noted, the Board would not be concerned about gas utility involvement in OPA-funded programs targeted at switching from electricity to gas. The Board's concerns are in connection with stand-alone electric CDM programs where the gas utilities take on a central role.

This leads to the issue of whether relief from the Undertakings is required for the utilities to engage in electric CDM. EGD's current CDM activities with THESL were approved in EGD's most recent rates case. This program, however, is clearly incidental to EGD's DSM activities and it does not entail a separate infrastructure. EGD is free to continue its relationship with THESL regarding the TAPS program, and either gas utility may engage in similar programs with other electric LDCs where the CDM activity is clearly incidental to the utilities' DSM activities, or to engage in electric CDM stand-alone programs aimed at switching from electricity to gas where no dedicated investment in electric infrastructure would be required.

However, it is certainly possible that some other electric CDM activities or programs would require relief from the Undertakings. The Board is not in a position to articulate these engagements. The Board has not heard sufficient evidence to determine what would be an appropriate involvement by the gas utilities in such circumstances. The Board will leave it to the utilities to make such proposals if they so wish when they come forward with their respective DSM plans.

What is the appropriate treatment of costs and revenues for electric CDM? (Issue 15.2)

and

What incentives, if any, should be paid for electric CDM activities? (Issue 15.3)

There was no settlement (complete or partial) on these issues.

The utilities proposed that the costing of electric DSM should be on an incremental basis and the net revenues be split 50/50 between shareholders and ratepayers. This is the current practice for the TAPS program between EGD and THESL which was approved in the EB-2005-0001 rate case decision.

Some intervenors argued for full costing on the basis that it would avoid concerns about cross-subsidy between gas and electricity ratepayers. Full costing would also lower the net revenues to be split, thereby reducing the utilities' incentive to divert resources from DSM to CDM activities that may be more lucrative.

The Board notes that there was no opposition by intervenors to the institution of the 50/50 net revenue split proposal. The Board accepts the proposal as reasonable.

The utilities' proposal to use incremental costing is not acceptable to the Board. Full costing has been the general practice for programs that are not part of the core utility business and the Board sees no reason to deviate from that practice in this case. Full costing avoids cross-subsidization from gas to electricity ratepayers and reduces the incentive to shift resources from gas DSM to electric CDM in pursuit of possibly more lucrative returns in the latter.

Having approved the incentives contained in the "financial package", the Board does not see the need for other incentives necessary or appropriate for gas utilities to engage in electric CDM activities at this time.

CHAPTER 5 – INPUT ASSUMPTIONS, COMMON GUIDE, AND NEXT STEPS

In this chapter the Board addresses Issue 3.2 which is whether there should be a common guide to specify what input assumptions should be used by the utilities, and deals with the next steps of this proceeding.

Prior to and during the oral hearing the Board indicated that the process of listing and valuing input assumptions would not be part of this phase of the proceeding and that the Board wished to hear from parties on the appropriate subsequent process.

Issue 3.2 was phrased as, should there be a common guide (e.g. TRC Guide for Conservation and Demand Management ("CDM")) to specify what input assumptions should be used by the utilities?

All intervenors agreed as follows:

> "No. The input assumptions should be included in each utility's plan, and should be updated for each Utility during the plan period in accordance with the partial settlement to issue 3.1."

The utilities endorsed the notion of a common list and common values (where appropriate) of input assumptions for the two utilities in a common document. They suggested that this document would be an appendix to a Guide document which would reflect the Board's decision and convert elements of the decision into an operational handbook. They argued that this would be consistent with the intent of the proceeding to develop a rules-based framework for DSM. The utilities further suggested that Board Staff could take ownership of the development of the Guide and become the custodian for future updates.

The utilities argued that the creation of a common document has several advantages. Many of the input assumptions are common and they could be updated in their entirety by a Board process every three years. There would be no question as to the input assumptions that the utilities are to use. Assigning Board Staff the responsibility of updating the input assumptions would impart discipline on parties seeking to change the input assumptions. The utilities noted that where there was a need for different input assumptions between EGD and Union, it would not be difficult to effect within the list.

SEC argued that common input assumptions was a non-issue since the process for amending and updating the assumptions is completely settled in issues 3.1, 3.3 and 3.4 and that the existence of a guide is not relevant to the inclusion or determination of input assumptions. GEC endorsed SEC's view and further argued that an input assumptions process may frustrate the settlement on those issues. GEC further suggested that the Board should rely upon the evaluation and audit process to consider input assumptions. Energy Probe endorsed the submissions put forward by GEC and SEC. LPMA submitted that each utility should include its input assumptions as part of its own plan but the utilities should work together to develop common input assumptions where appropriate. Some argued that translating the Board's decision into a guide amounted to a waste of time, and unless the Board drafted the Guide and handed it to parties in a finished version, parties would take the opportunity to re-argue issues in interpreting the Board's decision.

In the Board's view it is clear that TRC input assumptions will have to be determined before any DSM plans can be finalized. The Board also agrees that the process should be conducted under the Board's review as a second phase to the current proceeding. The Board feels that the most appropriate process for creating the input assumptions guide is one similar to that employed to create the CDM Handbook. The Board therefore directs Board Staff to circulate a draft of

an input assumptions guide. Parties will be given an opportunity to comment on the draft and, where they feel it necessary, to make submissions for changes with appropriate support. A Procedural Order will be issued which will set out the details of this process more fully. It is anticipated that this second phase to the proceeding will be completed before the end of 2006.

There are no persuasive reasons in the Board's view not to have a common list of input assumptions and common values with the exceptions of the values as noted in this decision. In fact it appears to the Board that there are efficiencies to be gained by the use of a common set of assumptions. To the extent that there may be differences in how the assumptions might apply to the two utilities or in the values themselves as allowed in the decision, these could be accommodated and highlighted within the generic set. There are only two gas utilities affected and it would not be administratively difficult to do so.

Once the initial list and measures of the input assumptions is determined, the issue then becomes: what is the process for updating these?

The completely settled issue 3.1 stipulates that the input assumptions will be updated on a regular basis during the plan period as part of each utility's ongoing evaluation and audit process. The Board has the ultimate authority to review and approve any changes. It appears to the Board that unless there is joint utility participation, the updates may occur at different times. This would not be efficient and would burden the regulatory process needlessly. The Board therefore concludes that the updating process should be centralized within Board Staff, at least for this first generation of multi-year DSM plans. The Board anticipates that the recommendations that come from the evaluation and audit

committee would, in effect, be the substance of the comments process to be employed for the updating of the list and values of the input assumptions. Any suggested updates to the input assumptions guide arising from the evaluation and audit process should be filed with the Board within one month of the end of the annual audit and evaluation. The suggested updates will be considered by the Board, and the guide will be updated if the Board decides it is necessary. Further Procedural Orders may be issued regarding updates to the guide.

The next issue is whether there should be a handbook.

While the Board sees the merits in having a stand-alone handbook, it has concluded that this initiative should not be undertaken at this time. In making this finding, the Board is cognizant of the time sensitivity and significant effort that will be required to develop the common list and measures of the input assumptions and the Board does not wish parties be distracted by the effort to develop a handbook at this time.

The Board will issue a Procedural Order commencing the next phase that will lead into the determination of the input assumptions. The role of Board Staff will be set out in that procedural order. Further Procedural orders will be issued as required from time to time for the Board to receive and rule in this matter and to cause the filing of the multi-year DSM plans by the utilities.

Intervenors eligible for cost awards shall file their cost claims by September 15, 2006. The utilities may comment on these claims by September 22, 2006. The cost award applicants may respond to the utilities' comments by September 29, 2006. Union and EGD shall pay in equal amounts the intervenor costs to be

awarded by the Board in a subsequent decision, as well as any incidental Board costs.

Dated at Toronto, August 25, 2006

Original Signed By

_____
Pamela Nowina
Presiding Member and Vice Chair

Original Signed By

_____
Paul Vlahos
Member

Original Signed By

_____
Ken Quesnelle
Member

APPENDIX 1

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0021

PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

Filed: 2008-09-26
EB-2008-0219
Exhibit E
Tab 3
Schedule 1
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PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

THE PROCEEDING

On February 15, 2006, the Board issued a Notice of Application that was published.

The Board issued Procedural Order No.1 on March 2, 2006, establishing the procedural schedule for all events prior to the oral hearing. These events included:

- EDGI and Union evidence filed by April 10, 2006;
- Issues conference on April 24, 2006;
- Issues Day on April 28, 2006;
- Technical Conference to replace interrogatories on EDGI and Union's evidence on May 11 and 12, 2006;
- Intervenor (non-utilities) evidence filed by June 1, 2006;
- Technical Conference to replace interrogatories on Intervenor (non-utilities) evidence on June 8, 2006;
- Half day Intervenor Conference on June 19, 2006;
- Settlement Conference beginning June 19, 2006;
- Settlement Proposal by June 28, 2006; and
- Board review of Settlement Proposal on July 6, 2006.

In response to Procedural Order No. 1, the Board received written evidence prepared by the following parties:

- Malcolm Rowan on behalf of Canadian Manufactures and Exporters ("CME");
- Paul Chernick on behalf of the School Energy Coalition ("SEC");
- Chris Neme on behalf of the Green Energy Coalition ("GEC"); and
- Roger Colton on behalf of Low Income Energy Network (LIEN").

On April 28, 2006, the Board issued Procedural Order No. 2, which established the Issues List for the proceeding.

On June 12, 2006, Procedural Order No. 3 was issued as a result of there not being adequate time to complete the questions on CME evidence within the one day Technical Conference. The Board ordered CME to provided written responses to SEC and GEC questions.

Procedural Order No. 4, issued June 28, 2006, provided the parties with an extension to file a Settlement Proposal with the Board.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board's offices.

Union Gas Limited ("Union")	Crawford Smith
Enbridge Gas Distribution ("EGD")	Dennis O'Leary
Board Counsel and Staff	Michael Millar Michael Bell Stephen McComb
Canadian Manufacturers & Exporters ("CME")	Brian Dingwall

Consumers Council of Canada ("CCC")	Robert Warren
Energy Probe	Norm Rubin
Green Energy Coalition ("GEC")	David Poch
Industrial Gas Users Association ("IGUA")	Vince DeRose
London Property Management Association ("LPMA")	Randy Aiken
Low Income Energy Network ("LIEN")	Juli Abouchar
Pollution Probe	Murray Klippenstein
School Energy Coalition ("SEC")	Jay Shepherd
Vulnerable Energy Consumer's Coalition ("VECC")	Michael Buonaguro

WITNESSES

There were 11 witnesses who testified at the oral hearing. The following EGD and Union employees appeared as witnesses at the oral hearing:

<u>EGD</u>	
Susan Clinesmith	Manager, Business Markets
Norman Ryckman	Group Manager, Business Intelligence and Support
Michael Brophy	Manager, DSM and Portfolio Strategy
Patricia Squires	Manager, Mass Markets and New Construction Market Development
<u>Union</u>	
Chuck Farmer	Director, Market Knowledge and DSM
Tracy Lynch	Manager, DSM

In addition, EGD called the following witness:

Dr. Daniel M. Violette	Principal and Founder, Summit Blue Consulting

Witnesses called by intervenors at the oral hearing:

Chris Neme (By GEC)	Director of Planning and Evaluation, Vermont Energy Investment Corporation
Malcolm Rowan (By CME)	President, Rowan and Associates Inc.
Roger D. Colton (By LIEN)	Consultant, Fisher, Sheehan & Colton

In addition, CME called the following witness:

Anthony A. Atkinson	School of Accountancy, University of Waterloo

RETURN ON EQUITY

1. The purpose of this evidence is to provide the return on equity ("ROE") used for the calculation of earnings sharing, if any, for 2008 and 2009 Historical Year. The Company has (or in the case of 2009, will calculate) ROE for 2008 and 2009 using the methodology provided in the Board's "Draft Guidelines on a Formula-Based Return on Equity for Regulated Utilities". This information is provided for reference purposes only.

2. In accordance with the Board's Decision in the Company's EB-2007-0615 rate case, Earnings sharing will be calculated "…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…" Table 1 shows the calculation of ROE for 2008.

Table 1
Determination of ROE for 2008

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

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

Based on the October 2007 Consensus Forecasts publication and the data provided in the Financial Post, ROE for 2008 is 8.66%.

3. Data are currently not available for the calculation of ROE for 2009. It is expected that the data will be available by mid-October 2008, at which point ROE for 2009 will be calculated and attached as an appendix to this Exhibit.

Witness: J. Denomy

APPENDIX A: RETURN ON EQUITY CALCULATION FOR 2009

1. The purpose of this appendix is to provide the return on equity (ROE) used for the calculation of earnings sharing, if any, for 2009. The Company has calculated ROE for 2009 using the methodology provided in the Board's "Draft Guidelines on a Formula-Based Return on Equity for Regulated Utilities".

2. Table A1 below shows the calculation of ROE for 2009.

Table A1
Determination of ROE for 2009

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Yield on 10s 3 Months Out[a]	Yield 10s 12 Months Out[a]	Average 10s Yield	Average Spread (30s-10s)[b]	Long Bond Forecast	Difference in Long Bond Forecast	0.75xDifference (Rounded to 2 Decimal Places)	ROE (%)
		(Col. 1+Col. 2)/2		Col. 3+Col. 4	Col. 5-4.61	0.75xCol. 6	8.66+Col. 7
3.50	3.80	3.65	0.49	4.14	-0.47	-0.35	8.31

Notes:
2008 ROE: 8.66
2008 Long Canada Forecast: 4.61
[a] From Consensus Forecasts October 13, 2008
[b] From Financial Post

Based on the October 2008 Consensus Forecasts publication and the data provided in the Financial Post, ROE for 2009 is 8.31%.

Witness: J. Denomy