Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2003-0203

IN THE MATTER OF AN APPLICATION BY

ENBRIDGE GAS DISTRIBUTION INC.

FOR RATES FOR FISCAL 2005

DECISION WITH REASONS

November 1, 2004

Summary of Decision – RP-2003-0203

This Decision deals with Enbridge Gas Distribution Inc.'s ("EGDI") application for a Board Order approving rates for its 2005 fiscal year commencing October 1, 2004. The majority of the issues were settled by the Parties, with the remaining matters being heard by the Board in an oral proceeding ending on August 3, 2004. The Applicant asked the Board to make an early decision on several issues to facilitate an October 1, 2004 implementation of new rates. For this reason, as well as to implement the Parties' Settlement Agreement, the Board issued a Partial Decision with Reasons on August 31, 2004 which in turn lead to interim rates being approved for October 1, 2004.

This Decision addresses the remaining five issues or groups of issues where agreement could not be reached by all Parties through settlement efforts. The Board's Decision on these matters will lead to a rate order implementing a modest reduction in distribution rates, which will be reflected in the Board's final rate order.

Chapter 2 of this Decision considers the Transactional Services ("TS") earnings Sharing Mechanism designed to share profits from the marketing of surplus EGDI transportation and storage assets. It also addresses the issue of, how and if. EGDI should include commodity in these transactions to maximize revenues.

The Board has found that the Company's current TS sharing mechanism should be continued, meaning that $8.0 million is guaranteed to ratepayers in rates, the next $2.7 million goes to the shareholder, and any remaining amounts are shared 75% going to ratepayers and 25% to the shareholder. The Board has decided that it is not appropriate for either EGDI, or its affiliate Enbridge Gas Services Inc. ("EGS") as agent for EGDI, to acquire gas commodity to be bundled with utility TS assets. In this regard, the Board's view is that TS should be made available on an open market basis to all interested parties. The Board has stated that it expects EGDI to develop a methodology for making surplus TS assets known to, and available to other market participants, in addition to EGS.

In Chapter 3 the Board considers the costs consequences of a new gas storage contract between EGDI and Union Gas Limited ("Union Gas"), which establishes a 10-year term, with market-based rates, as opposed to the historic cost-based rates. The Board has denied EGDI's request for recovery of the cost consequences of this contract, which by agreement, initiates a return to the previous cost-based rates. This return to the previous rates will result in a $2.7 million cost savings in the 2005 rate year. This short-term benefit carries with it the risk of a longer-term higher cost, but the Board lacked confidence in the evidence supporting the prospects of a long-term benefit and could not justify higher costs to ratepayers in the short-term.

Chapter 4 of this Decision contains the Board findings on EGDI's proposed changes to its gas supply risk management program designed to reduce natural gas price volatility. The changes include the removal of the 10% restriction on hedgeable volumes, the use of a 12-month rolling hedge period, and a customer risk tolerance survey. The Board has approved the changes, but in so doing has directed EGDI to file proposed revisions to the quarterly rate adjustment methodology ("QRAM") to recognise the effects of the new 12-month hedging period.

Chapter 5 concerns the disposition of the deferred tax liability issue relating to the October 1, 1999 unbundling of EGDI's hot water tank rental business and its eventual sale to a third party. The Board has authorized EGDI to collect from ratepayers, $23.9 million over three years starting October 1, 2004. The Board relied on the guidance provided in past decisions on this subject and found that the amount of $23.9 million was an accurate representation of the deferred taxes that became payable between October 1, 1999 and May 7, 2002 in 3696669 Canada Inc., the entity set up to hold the rental program assets.

The final substantive matter as outlined in Chapter 6, surrounds the impacts of EGDI's proposal to change its fiscal year-end from September 30 to December 31, to match the calendar year and its parent Enbridge Inc.'s fiscal year. EGDI proposed to make the transition via a three-month special “Stub Period” to take it from fiscal 2005, ending on September 30, 2005 to fiscal 2006, commencing on January 1, 2006.

The first impact results from a request for an increase in rates for the Stub Period of October, November and December 2005. The Board denied EGDI’s request for the increase, because it was not sufficiently convinced that the inflationary adjustment proposed, would result in a new rate that appropriately reflected cost increases in the Stub Period. The Board also rejected Intervenors’ requests to reduce rates by applying a lower return on equity for the Stub Period, finding it inappropriate in this case to use a return on equity other than the usual 12-month ROE. These findings resulted in the Board determination, that there will be no inflationary cost increase applied to the Stub Period of October to December 2005.

The Board resolved other issues brought about by the change in fiscal year end. These included the impacts on: the clearance of deferral accounts, the TS sharing mechanism, the impact on the Demand Side Management program and the implementation plan for the upstream storage and transmission cost allocation changes.

As a result of this Decision with Reasons, the Board will issue an order approving final rates for 2005, which will be implemented January 1, 2005 in conjunction with the regular quarterly adjustment to the natural gas commodity rates (QRAM).

This summary does not form part of the Decision and is not to be relied on for the purpose of applying or interpreting the Decision.

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RP-2003-0203

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing October 1, 2004.

BEFORE: Bob Betts
Presiding Member

Paul Sommerville
Member

Pamela Nowina
Member

DECISION WITH REASONS

November 1, 2004

1. INTRODUCTION

1.1 THE APPLICATION

1.1.1 Enbridge Gas Distribution Inc. (“EGDI”, “Enbridge”, the “Company”, the “Utility” or the “Applicant”) filed an application dated December 17, 2003 with the Ontario Energy Board (the “Board”) under section 36 of the *Ontario Energy Board Act, 1998*; S.O. c.15, Schedule B, for an order or orders approving or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas for EGDI’s 2005 fiscal year commencing October 1, 2004 (“2005 Test Year” or “Test Year”). The Board assigned file number RP-2003-0203 to the Application.

1.2 THE PROCEEDING

1.2.1 On December 19, 2003 the Board issued a Notice of Application which was published and served in accordance with the Board’s direction.

1.2.2 The Board issued on February 2, 2004 Procedural Order No.1 establishing the procedural schedule for all events prior to the oral hearing. These events included:

- A stakeholder conference on February 6, 2004;
- Written interrogatories to the Applicant by February 20, 2004;

- Written interrogatory responses from the Applicant by March 5, 2004;
- Issues Conference on March 9, 2004;
- Issues Day on March 16, 2004;
- Supplementary written interrogatories to the Applicant by April 16, 2004;
- Supplementary interrogatory responses from the Applicant by April 26, 2004;
- Intervenor evidence filed by May 3, 2004;
- Written interrogatories on Intervenor evidence by May 10, 2004;
- Responses to written interrogatories on Intervenor evidence by May 19, 2004;
- Motions objecting to sufficiency of any interrogatory response by May 21, 2004;
- Intervenor Conference on May 25, 2004;
- Settlement Conference beginning May 26, 2004;
- Settlement Proposal by June 10, 2004;
- Board review of Settlement Proposal on June 14, 2004.

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

- Robert D. Knecht on behalf of the Consumers Association of Canada and the Consumers Council of Canada (collectively, "CAC") and the Vulnerable Energy Consumers Coalition ("VECC");
- Tom Adams on behalf of Energy Probe Research Foundation ("Energy Probe");
- Chris Neme on behalf of the Green Energy Coalition ("GEC"), David Suzuki Foundation, Energy Action Council of Toronto, Greenpeace Canada and the Sierra Club of Canada;
- Peter Fournier on behalf of the Industrial Gas Users Association ("IGUA");
- Peter J. Milne on behalf of the School Energy Coalition ("SEC") and Energy Probe;

- Steve Emond, Thomas Robinson and Dean Ferguson on behalf of TransCanada PipeLines (“TCPL”);

1.2.4 The following parties filed evidence in confidence:

- Jim Stephens and Mark Wolnik on behalf of CAC, SEC, VECC, and IGUA;
- Amy-Lynne Williams on behalf of the CAC, SEC, VECC, and IGUA.

1.2.5 On March 2, 2004, the Board issued Procedural Order No. 2 which granted an extension for the filing of the written interrogatory responses by the Company to March 12, 2004. The Order also rescheduled the Issues Conference from March 9, 2004 to March 23, 2004 and the Issues Day from March 16, 2004 to March 25, 2004.

1.2.6 On Issues Day the Board heard submissions from EGDI, SEC, the Canadian Manufacturers and Exporters (“CME”), the Pollution Probe Foundation (“Pollution Probe”), TCPL, Petro Canada, Energy Probe, Direct Energy, Ontario Energy Savings Corporation (“OESC”) and Superior Energy Management (“SEM”). In addition, written submissions from CAC, IGUA, and VECC were read into the record by Board staff. On April 1, 2004, the Board issued Procedural Order No. 3 which recast the wording of Issue 5.5 as a result of the submissions on Issues Day. The Order also established the Issues List for the proceeding which is attached as Appendix A to this Decision with Reasons.

1.2.7 Procedural Order No. 4, issued April 30, 2004, made the following schedule changes:

- Motions regarding the sufficiency of any filed interrogatory response by May 7, 2004;
- Board hearing, if any, of May 7, 2004 motions on May 14, 2004;
- Intervenor Conference on May 17, 2004;
- Settlement Conference commencement on May 18, 2004;

- Settlement Proposal to be filed with the Board on June 9, 2004;
- Evidentiary phase of the oral hearing commencement on June 16, 2004.

1.2.8 The Board received letters dated May 3 and 4, 2004 from Intervenor groups requesting an extension to the filing deadline for the following evidence:

- SEC and Energy Probe regarding Gas Transportation Markets;
- CAC, SEC, VECC and IGUA regarding the EnVision Project;
- IGUA regarding various issues.

In Procedural Order No. 5, issued May 5, 2004, the Board granted an extension to May 7, 2004. Interrogatories arising from this evidence were to be filed no later than May 13, 2004.

1.2.9 The Settlement Conference commenced on May 18, 2004 and concluded on June 8, 2004. The following parties participated: CME, Casco Inc. ("Casco"), Coalition for Efficient Energy Distribution ("CEED"), CAC, Direct Energy, Energy Probe, GEC, IGUA, Maple Lodge Farms ("MLF"), Markham District Energy Inc. ("MDE"), Ontario Association of Physical Plant Administrators ("OAPPA"), OESC, Pollution Probe, SEC, SEM, TransAlta Energy Corporation ("TransAlta"), TCPL, Union Gas Limited ("Union") and VECC.

1.3 THE SETTLEMENT PROPOSAL

1.3.1 A June 10, 2004 Settlement Proposal was filed with the Board and, on June 14, 2004, the Applicant indicated that there were several issues still under negotiations. The final version of the Settlement Proposal was filed with the Board on June 17, 2004. This version was updated to include the full settlement of issues 7.1 and 8.1. The Board's final acceptance of the Settlement Proposal was given on June 18, 2004. A copy of the 59-page Settlement Proposal is attached as Appendix B to this Decision with Reasons.

1.3.2 Of the 61 issues on the Issues List, the Settlement Proposal included complete settlement of 48 issues and indicated that parties would not address these issues at the hearing. The remaining issues fall into one of the following two categories:

- Partial Settlement (four issues – one or more parties disagreed with the proposed settlement)
- No Settlement (9 issues –parties were unable to reach a settlement on one or more parts of the issue)

1.3.3 The following issues were presented in the Settlement Proposal as having been completely settled and will not be reviewed in this Decision:

Issue 1.1	Gas volume forecast for the 2005 Test Year
Issue 1.2	Proposed change in the degree day forecasting methodology
Issue 2.1	Other revenue including revenue from service charges
Issue 3.1	Review of the updated Conditions of Service governing the relationship between Enbridge Gas Distribution and its customers
Issue 3.2	Customer Security Deposit Policy
Issue 3.3	Disconnection Policy
Issue 5.3	Enbridge Operational Services Inc. (EOS) and Enbridge Gas Services (EGS) Service Level Agreements (filed per para 829 of the Board's RP-2002-0133 Decision with Reasons) and EOS and EGS costs (per para 524 of the Board's RP-2002-0133 Decision with Reasons)
Issue 5.4	System Gas and Direct Purchase gas costing methodology studies, including Enbridge Gas Distribution's proposal to retain the existing costing method (per Issue 6, parameters of the FAC studies, of the RP-2003-0048 Settlement Proposal)
Issue 6.1	Establishment of the return on equity for the 2005 Test Year using the Board's Return On Equity (ROE) Guidelines
Issue 6.2	Estimates of the cost of short-term and long-term debt for the 2005 Test Year

Issue 7.1	Capital Budget for the 2005 Test Year including capitalized O&M expenses
Issue 7.2	Economic Feasibility Procedure and Policy
Issue 7.3	Property Plan Update Report
Issue 7.4	Information Technology Capital Budget
Issue 7.5	Energy Transaction, Reporting, Accounting and Contracting (EnTRAC) information technology project
Issue 8.1	EnVision Project
Issue 9.1-9.12	Overall O&M levels for 2005, O&M for Finance Engineering Department, Customer Support, Opportunity Development, Regional Operations, Natural Gas for Vehicles, Gas Storage Operations, Strategic and Key Accounts, Human Resources, Legal, Regulatory and Public Affairs, Information Technology Department
Issue 9.13	2005 Non-Departmental O&M Expenses
Issue 9.14	Affiliate Transactions and Non-Utility Elimination
Issue 9.15	Corporate Cost Allocations including the Deloitte Report
Issue 10.3	Recovery of SSM and Lost Revenue Adjustment Mechanism (LRAM) amounts for 2002 and 2003
Issue 10.4	Recovery of DSMVA for 2001 and 2002
Issue 11.1	Amounts and proposed disposition of balances in historic deferral and variance accounts
Issue 11.3	Request to establish a 2005 Manufactured Gas Plant Variance Account
Issue 14.1	Proposed changes to the existing cost allocation methodology including the following: a) Upstream Transportation Costs b) Interruptible Service Differential/Credits c) M12 Transmission Related Costs d) Deliverability Allocation Factor e) Peaking Service Costs f) TransCanada Pipeline STS Costs g) Reference Price for Commodity costs h) Vector (Chicago) Commodity Purchases i) Storage Fluctuations and Unaccounted For Gas (UFG) j) Seasonal Credits for Rate 135 k) Transactional Service Credits to

	Ex-Franchise Customers l) Calculation of peak day for large volume customers
Issue 15.3	Rate 6 monthly customer charge
Issue 15.4	The rate design implications of proposed cost allocation changes or upstream transportation, storage, peaking service and interruptible credits
Issue 15.5	Proposal to eliminate the T-Service credit and unbundle the transportation charge from the Load Balancing Charge
Issue 15.6	Proposal for changes to the Annual Minimum Bill
Issue 15.7	Proposal for changes to the Rate Handbook
Issue 15.8	Proposal for changes to the Direct Purchase Administration Charge
Issue 15.9	Unauthorized Overrun Charges
Issue 15.10	Curtailment Notice
Issue 15.11	Review of QRAM methodology regarding the timing of the disposition of PGVA balances and its components, including the treatment of material adjustments from the previous fiscal year
Issue 16.1	Implementation of upstream cost allocation proposals
Issue 16.2	Implementation of other rate design changes
Issue 16.3	Rate implementation proposals

1.3.4 This Decision with Reasons will address the following issue groupings for which there was no settlement and which have not already been dealt with by the Board in the RP-2003-0203 Partial Decision:

- Transactional Services
- Union Gas Storage Contract
- Risk Management
- Deferred Taxes
- Change in Year End

1.4 MOTION BY OESC AND SEM REGARDING ISSUE 5.5 (SYSTEM GAS)

1.4.1 Procedural Order No. 4 asked that Parties wishing to make submissions regarding the sufficiency of any filed interrogatory responses do so by May 7, 2004 and that the Board would hear any resulting motions on May 14, 2004. OESC and SEM filed a joint motion on May 7, 2004 with respect to Issue 5.5. The moving parties requested that the Board order the evidence filed by EGDI be removed from the record of the proceeding.

1.4.2 On May 13, 2004 the Board received submissions from TCPL and VECC opposing the motion.

1.4.3 The Board heard the motion on May 14, 2004 and issued its written Decision on Motion on May 27, 2004. The motion was denied and the Decision on Motion is included as Appendix C to this Decision.

1.5 MOTION BY ENBRIDGE GAS DISTRIBUTION INC. REGARDING ISSUES 13.1 AND 13.2 (CHANGE IN FISCAL YEAR END)

1.5.1 The Company filed a written motion on June 11, 2004 to have issues 13.1 and 13.2 removed from the Issues List. The Board heard submissions on the motion on June 18, 2004 and rendered its oral decision on June 21, 2004. The Board denied the motion.

1.6 CLAIM FOR CONFIDENTIALITY REGARDING ISSUE 12.1 (DEFERRED TAXES)

1.6.1 On June 25, 2004, Day 7 of the oral hearing, the Board heard submissions on the Company's claim for confidentiality in respect of some of the deferred taxes documentation. On the same day, the Board denied the Company's request, indicating in its oral decision that the Company had not demonstrated to the Board's satisfaction that there was justification for the exclusion of the documents from the public record.

1.7 PARTIAL DECISION ISSUED ON AUGUST 31, 2004

1.7.1 On August 3, 2004 the Company had requested an expedited decision to enable it to reflect the impact of the Board's decision respecting Issues 15.1 (termination of rate seasonality) and 15.2 (proposed increase in the fixed customer charge for certain customers) in the new rates which would be effective October 1, 2004, coincident with the rate adjustment flowing from the Quarterly Rate Adjustment Mechanism ("QRAM").

1.7.2 In addition, Pollution Probe requested the Board make an expedited decision regarding Issue10.1 (large boiler market transformation program) so that, if approved, the program could be in place for January 1, 2005.

1.7.3 The Board issued a Partial Decision with Reasons regarding RP-2003-0203 on August 31, 2004. The Partial Decision is included as Appendix D to this Decision.

1.8 INTERIM RATE ORDER ISSUED ON SEPTEMBER 27, 2004

1.8.1 On September 3, 2004, EGDI filed a proposal for a rate order, which was to be effective October 1, 2004. It contained the following elements:

- Rates designed to recover a 2005 test year revenue requirement of $2.9 billion;
- The first year of the 4-year phase-in of the agreed upon cost allocation changes;
- Unit rates for the one-time disposition of the 2003 PGVA customer refund of $82.9 million;
- Unit rates for the one-time disposition of 2004 deferral and variance accounts totaling $4.0 million; and
- Accounting treatment descriptions for all 2005 deferral variance accounts.

1.8.2 On September 27, 2004, the Board issued an Interim Rate Order, approving the September 3, 2004 proposal. The Board noted that a final rate order would be approved after the Board has dealt with the remaining unsettled issues in a Decision with Reasons.

1.9 QUARTERLY RATE ADJUSTMENT MECHANISM

1.9.1 During the course of the 2005 Test Year proceeding, EGDI made three separate applications to the Board and the Board issued interim orders to implement, effective April 1, 2004, July 1, 2004 and October 1, 2004, respectively, adjustments to EGDI's commodity rates under the approved quarterly rate adjustment mechanism.

1.9.2 The QRAM applications were assigned the following file numbers:

- EB-2004-0209 relating to the April 1, 2004 QRAM
- EB-2004-0266 relating to the July 1, 2004 QRAM
- EB-2004-0428 relating to the October 1, 2004 QRAM

1.9.3 The complete record for each of the QRAM proceedings, including the application, submissions, hearing transcript, if any, and the Board's Decision and Order can be found under the respective QRAM docket numbers listed above.

1.10 PARTICIPANTS AND THEIR REPRESENTATIVES

1.10.1 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 on the record.

Board Counsel and Staff	Jennifer Lea Mike Lyle Colin Schuch James Wightman Richard Battista
Enbridge Gas Distribution Inc.	Fred Cass Marika Hare

	Tom Ladanyi Dennis O'Leary Tania Persad
Consumers Association of Canada & Consumers Council of Canada	Robert Warren Julie Girvan
Vulnerable Energy Consumers Coalition	Michael Janigan Roger Higgin
Industrial Gas Users Association	Peter Thompson
School Energy Coalition	Jay Shepherd Darryl Seal
Green Energy Coalition	David Poch
Direct Energy Marketing Limited	Melanie Aitken Pascale Duguay
Coalition for Efficient Energy Distribution, Ontario Energy Savings Corporation, Superior Energy Management, TransAlta Energy Corporation	Elisabeth DeMarco
Canadian Manufacturers & Exporters	Malcolm Rowan Carol Street
Pollution Probe	Murray Klippenstein Jack Gibbons
Energy Probe	Brian Dingwall Tom Adams David McIntosh
Ontario Association of Physical Plant Administrators, Casco, Maple Lodge Farms, Markham District Energy	Valerie Young
TransCanada PipeLines	Murray Ross
Union Gas Limited	Patricia Jackson Jim Laforet

Witnesses

1.10.2 There were 23 witnesses who testified at the oral hearing.

1.10.3 The following Company employees and Enbridge Inc. employees appeared as witnesses at the oral hearing:

Mark Boyce	Associate General Counsel and Corporate Secretary
Bradley Boyle	Assistant Treasurer, Enbridge Inc.
Frank Brennan	Director, Energy Policy and Analysis
Dave Charleson	Manager, Energy Strategy
Susan Clinesmith	Manager, Business Markets and Communications Development
Jackie Collier	Manager, Rate Design
Kevin Culbert	Manager, Regulatory Accounting
Malini Giridhar	Manager, Rate Research and Design
Colin Gruending	Director, Investor Relations, Enbridge Inc.
Marika Hare	Director, Regulatory Affairs
Guy Jarvis	Vice President, Enbridge Gas Services Inc.
John Jozsa	Manager, Tax Services
Tom Ladanyi	Manager, Regulatory Proceedings
Steve McGill	Manager, Strategic Projects & Market Analysis
Arunas Pleckaitis	Vice President, Opportunity Development
William Ross	Director, Finance & Control

Fred Rubino	Manager, Supply Services
Norman Ryckman	Group Manager Utility Planning & Evaluation
Don Small	Manager, Gas Cost Knowledge Centre
John Whelen	Treasurer

1.10.4 In addition the Company called the following witnesses:

Tim Simard	RiskAdvisory, Principal Consultant
Theodore Spevick	Partner, KPMG Chartered Accountants

1.10.5 Witnesses called by Intervenors:

Peter Fournier	President, Industrial Gas Users Association

1.11 SUBMISSIONS AND EXHIBITS

1.11.1 Copies of the evidence, exhibits, arguments, and transcripts of the proceeding are available for review at the Board’s offices.

1.11.2 The Board has considered all of the evidence, submissions, and arguments in the proceeding, but has summarized the evidence and the positions of the Parties only to the extent necessary to provide context for its findings.

2. TRANSACTIONAL SERVICES

2.1 BACKGROUND

2.1.1 Issue 4.1 on the Issues List deals with the proposed Transactional Services ("TS") sharing mechanism for the 2005 Test Year. Issue 4.2 deals with the Company's proposal to sell natural gas commodity bundled with utility assets as part of Transactional Services. The Board found in writing this Decision that the two issues are inseparable, as the Company has proposed different sharing mechanisms depending on the allowance or disallowance of bundled commodity transactions. Therefore, issues 4.1 and 4.2 will be discussed together.

2.1.2 Since the fall of 2002, the Company has been bundling natural gas commodity with EGDI utility assets (assets used to offer services such as peak storage, off-peak storage, loans, exchanges, load-balancing and transportation assignments) to create bundled transactions. The Company's proposed changes to the TS business are related to these bundled transactions. The Company presented several proposals. The first such proposal would allow Enbridge Gas Services Inc. (EGS), an affiliated company, to conduct commodity transactions in the name of Enbridge Gas Distribution Inc. Under this proposal EGDI would be permitted to deduct all credit costs from the gross margin prior to sharing the proceeds with ratepayers. In this situation, EGDI also proposed that the current sharing mechanism remain the same; that is, the first $8 million is guaranteed to ratepayers, the next $2.7 million goes to the shareholder, and the remaining revenues are to be captured in the Transactional Services Deferral Account for future disbursement, that being 75 percent to ratepayers, 25 percent to the shareholder; all O&M costs would be borne by the shareholder.

2.1.3 Under the second proposal, if the Board does not allow EGDI to conduct commodity transactions its own name, then it has requested that EGS be allowed to continue to conduct commodity transactions as EGDI's agent and charge back to EGDI any associated credit costs. EGDI would then deduct these credit costs from the gross margin prior to any sharing, and the sharing mechanism would be the same as described earlier. EGDI has estimated these credit costs at $2 million dollars annually, but has suggested that an independent third party provide an expert opinion as to the quantum of the credit costs for the next rate application.

2.1.4 If the Board allows neither of the above scenarios, the Company offered the third proposal, that it would no longer engage in bundled commodity transactions. That scenario would require the sharing mechanism be changed to provide for the first $4.5 million being guaranteed to ratepayers, the next $1.3 million going to the shareholder, and the balance being captured in the TS deferral account for future disbursement in the ratio of 75 percent to ratepayers, 25 percent to the shareholder.

2.1.5 In all cases the O&M costs would be borne by the shareholder.

2.1.6 The questions before the Board can be summarized as:

- Should the Board allow EGDI, EGS or neither to enter into commodity transactions in order to create bundled products of commodity and utility asset services?

- Depending on the answers to the above question, who should take on the credit risk costs of the commodity transactions? What is the appropriate budget for these costs?

- Depending on the decisions the Board makes on the previous questions - what is the appropriate sharing mechanism for Transactional Services' margins?

2.2 COMMODITY TRANSACTIONS (POSITIONS OF THE PARTIES)

Position of the Company

2.2.1 EGDI argued that TS had provided benefit to ratepayers and that Transactional Services bundled with commodity had provided substantial additional benefits. In 2003, the gross margin related to commodity-bundled transactions was $10.5 million. The Company filed an exhibit on June 22, 2004 that indicated that the 2004 year-to-date gross margin amount was $13.6 million.

2.2.2 EGDI suggested that the utility assets bundled with commodity might not otherwise have been utilized as fully. The Company's evidence states that bundled transactions are used to generate Transactional Services revenue where there would otherwise be no opportunity to sell Transactional Services alone for similar value, or to capture certain short-term intra-day opportunities.

2.2.3 The Company submitted that there was no evidence of any negative impact on any specific entity or the competitive market in general as a result of the bundling of commodity with TS, and there was no evidence that this practice will have a negative impact in future.

2.2.4 Regarding Intervenors' concern about a lack of transparency in these transactions, the Company claimed that there was very transparent pricing for bundled Transactional Services. The Company stated that the purchasers of the Company's TS offerings are sophisticated market participants who are fully aware of the prevailing price for the commodity and are experienced traders in TS assets. The Company asserted that if a pricing update is required or some competitive comparison is needed, such traders have the ability to determine whether the bundled TS offering of the Company is reasonable.

2.2.5 The Company submitted that the bundled transactions are not covered by the agency agreement between EGDI and EGS. Although the entire margin is paid to EGDI, it is EGS that buys and sells the commodity portion of the bundled TS as principal. Therefore, the activity is not covered by the agency agreement, and hence there is no breach of that agreement**.**

2.2.6 The Company argued that any Intervenors opposed to the bundling had from November 2003 (when they were first informed of the bundled transactions) to contact relevant market participants and to retain appropriate experts for the purposes of creating an evidentiary record in this proceeding in support of their concerns. The Company submitted that there is no evidence to provide a basis to prohibit this activity that provides significant benefits to ratepayers.

Positions of the Intervenors

2.2.7 Several ratepayer groups, including CAC, SEC and IGUA submitted that there was no evidence presented to demonstrate that there was a significant adverse impact on the market, or on EGDI's ratepayers, of undertaking the bundled transactions. These Intervenors pointed out that these bundled transactions enhance the value of the surplus storage and transportation assets and provide ratepayers with revenue that would otherwise be unavailable. Therefore, these Intervenors supported a regime that allows Transactional Services to be bundled with a commodity component.

2.2.8 CME's position on the other hand, was that there is a market concern regarding the bundling of commodity services, and that EGDI should not be authorized to purchase natural gas commodity as a principal and bundle it with its TS assets. CME also indicated, that if there is going to be a competitive market, to allow EGS to act as an agent for EGDI impacts on others in that market. It was CME's view that EGS should only have that right to perform this service if it succeeds at tender and has to compete in the open market with others who might want that opportunity as well. CME submitted that the Company acknowledged that in the current situation, EGS does not in every case canvass the market to see if the TS assets can be sold without bundling with commodity, before EGS offers the bundled product. Nor does EGDI advise other marketers of the availability of the surplus TS assets.

2.2.9 While some ratepayer Intervenors agreed with the continuation of commodity bundled transactions, Intervenors generally agreed that these transactions should not be carried out with EGDI as principal. They believed that EGDI's gas commodity acquisition activities should be confined to the acquisition of the gas commodity needed to meet its utility system requirements, and the requirements of its system-gas users. The view was that EGDI and its ratepayers should not be exposed to the risks of gas commodity trading beyond the risks related to the management of utility system gas. Accordingly, if bundled transactions are to occur, EGS should conduct the commodity portion in its own name, as EGDI’s agent.

2.2.10 CEED and Direct Energy were opposed to the Utility's participation in the competitive natural gas commodity market, either directly, or indirectly through EGS. They argued that the effect of EGDI's proposal to bundle TS assets together with commodity would be to allow the Company to exploit its monopoly for TS assets in an anti-competitive way, creating an unfair advantage that is inconsistent with a competitive marketplace. The retailers see this as a fundamental shift in natural gas policy established by previous Board decisions (CEED referenced EBRO-492) and not supported by existing authorizations under the agency agreement between EGDI and EGS. These Intervenors asserted that EGS is not authorized under the agency agreement to sell commodity or to sell bundled commodity with TS assets. They stated that the agency agreement lists the various things that EGS is entitled, as agent, to sell on behalf of EGDI, and that list does not include the commodity.

2.2.11 Direct Energy stated that commodity is supposed to be the subject of a competitive market, and allowing a monopoly product to be bundled with it, fundamentally undermines such a competitive dynamic. CEED maintained that the sale of the bundled transactions is detrimental to competition in the Ontario natural gas market by decreasing transparency in the market and providing the Utility or its affiliates with information and opportunities that are not available to other market participants. Direct Energy stated that the normal market checks and balances cannot operate in this situation. They stated that there is no market and therefore, no market price, for this bundled product. Only EGS offers it, and the only price constraint on a monopolist is a demand curve. They indicated that this might encourage EGS to hold TS assets off the market while they're waiting for a good trading opportunity. A further concern is that the offer of the bundled product may deprive the retail marketers of the opportunity to bid for the commodity component of that business.

2.2.12 CEED expanded on its concern regarding the affiliate's access to and use of Utility information. CEED requested that, based upon its RP-2001-0032 and RP-2002-0133 decisions, the Board prohibit EGDI and its affiliates from using the information they acquire or generate in providing utility services to market or sell gas, or for any other purpose other than utility services. Specifically, CEED submitted that in Board decision RP-2001-0032, the Board ordered the Company to establish that the information provided to its affiliates would not be used to the detriment of ratepayers or to the competitive market. CEED also submitted that despite the Board's increasing focus and exercise of jurisdiction over these matters, the Company offered further competitive market services. CEED requested that the Board order the amendment of the EGS and EOS outsourcing agreements to prohibit EGDI from contracting out utility services to a third party that provides competitive gas or electricity sales services.

2.2.13 CEED and Direct Energy also argued that the Company has not proven that the sale of commodity is necessary to optimize the value of transactional service assets. They submitted that the revenue from the sale of unbundled TS assets was growing considerably in a "challenged market", citing evidence that gross margins attributable to unbundled TS assets grew from $5.7 million in 1998 to $14.1 million in 2001. In the "corrected" market of 2002 the TS-only margins were $9.36 million, still an increase from 1998. CEED stated that there was no credible evidence the TS portion of the bundled transactions would disappear if another market participant were supplying the commodity

2.2.14 Both CEED and Direct Energy stated that the Company has the burden to prove that the information or opportunities provided to the affiliate are not to the detriment of the competitive market. They stated that the Company had not discharged this duty.

2.2.15 Energy Probe supported the view of the retailers that the lack of transparency of the bundled transactions allowed the possibility that profits might flow out of the bundled transaction into a third party's hands. Energy Probe was concerned that the bundling of utility assets by a utility affiliate with non-regulated assets, raises a number of questions regarding transparency. Energy Probe also argued that the evidence indicated that the bundled commodity transactions have created a significant and material change to the risk profile associated with the performance of Transactional Services to the point where EGS has, of necessity, required parental guarantees in excess of $100 million in order to perform these functions.

2.3 CREDIT RISK (POSITIONS OF THE PARTIES)

Position of the Company

2.3.1 The Company has proposed that EGS conduct commodity transactions in the name of EGDI, in which case EGDI incurs the associated credit costs. If the Board does not accept this proposal, the Company’s less preferred alternative is that EGS continue to conduct the commodity transaction in its own name but transfer the credit costs to EGDI. EGS is no longer willing to be responsible for these costs, which include posting a line of credit or parental guarantee to backstop the value of the commodity. The Company also noted that EGS has no way of recovering any “bad debt” related to the commodity transaction and that these risks should be borne by EGDI. The Company recommended that the credit costs be deducted from the TS gross margin, prior to sharing.

2.3.2 The Company's witnesses estimated these costs to be approximately $2 million, based on the stand-alone cost of a third party providing a letter of credit for a $100 million dollar maximum exposure, or a statistical analysis as to what amount of economic capital would be required to reserve against the same loss.

2.3.3 EGDI noted that to date all of the risks to the commodity asset with bundled transactions have been borne by EGS. While the risk of default by approved, creditworthy counterparties was described as being small, the Company asserts that EGS alone was exposed to default with respect to the $275 million in commodity revenues for 2003.

2.3.4 In the Company's view, the most cost-effective approach to manage the risks of bundled transactions would have EGS conducting commodity transactions in the name of the Utility. In this scenario the Company proposed that EGDI take on the commodity credit risk, in a manner similar to self-insurance. The Company believes that, given EGDI's credit position, it would incur little or no credit costs. The Company's witnesses described the risk probability factor associated with approved creditworthy counterparties as very small, ranging between 0.01 and 0.05 percent. The Company submitted that the risk to ratepayers, if the commodity transactions were undertaken with EGDI as principal, would be minimal and therefore should not be of concern. They ascribed this lack of risk to the credit worthiness of the counterparties, the history of Transactional Services over 9 years with no counterparty failures, and the very specific exposure limits for counterparties that EGDI could set.

2.3.5 In the Company's prefiled evidence it was noted that EGS has indicated a reluctance to enter into commodity transactions in its own name because of the credit costs and the risk that it may not be able to recover bad debt.

2.3.6 The Company stated that, if the Board concluded that EGS should continue to conduct the commodity transactions in its own name, EGS should be appropriately compensated for its credit risk costs. The Company argued that it is both logical and fair to allocate the cost of credit risk to those parties who benefit from the activity creating the credit risk.

2.3.7 The Company also stated that if its estimate of the $2 million credit cost isn't thought to be adequately substantiated, that an independent third party could be retained to establish an appropriate charge in light of what a financial institution or other guaranteeing entity would require to carry on this sort of business.

Positions of the Intervenors

2.3.8 The Intervenors representing ratepayers were of the view that the Company had not justified the recovery of any credit costs from ratepayers. Most Intervenors cited the lack of concrete evidence in support of the proposed credit cost of $2 million, stating that the Company had failed to demonstrate how a reasonable amount should be derived, or that the estimated amount of $2 million is reasonable. They also stated that while a third party assessment to justify amounts would be appropriate for future applications, it was not appropriate to do this retrospectively for the 2005 rate year, as the Company had already had its opportunity to present its case. Similarly, there was no support for a deferral account to record costs.

2.3.9 VECC stated that ratepayers are not willing to have credit costs deducted from the gross margin, before sharing of revenues from TS, as requested by EGS and EI. In VECC’s view, this approach would increase the shareholder’s share of revenue by the amount of the credit costs.

2.3.10 The retailers submitted that EGS’s competitors in selling commodity don't have the ability to pass on credit costs to another party and that the Board should deny EGS's request to shift to ratepayers the credit costs associated with their commercial trading in the commodity.

2.3.11 CAC stated that if the Board accepts the Company’s argument that some recovery of credit costs be allowed, the amount should not exceed $50,000 (the amount the Company projected as actual credit costs for the test year).

2.4 SHARING MECHANISM (POSITIONS OF THE PARTIES)

Position of the Company

2.4.1 The Company did not accept the Intervenors' position that the TS estimated gross margin budget of $15 million should impact the sharing mechanism. The Company argued that the current sharing arrangement guaranteed the ratepayer $8 million in rates. Any shortfall of the guaranteed amount would be at the cost of the shareholder who would incur unrecoverable operating costs if the margin were not sufficient. Any gross margin above $10.7 million would be shared 75% for the ratepayers and 25% for the shareholder. The Company described the impact as a deferral of the ratepayers' benefit. Therefore, the Company argued, that the negative impact to ratepayers of a simple deferral of gross margin, if gross margin is overachieved, is less than the negative impact to shareholders, if gross margin does not achieve the guaranteed amount.

2.4.2 The Company submitted that the Board has approved the sharing mechanism at its current levels of $8 million and $2.7 million, respectively, in previous years and therefore it is a fair mechanism that can be relied upon in future.

2.4.3 The Company also submitted that if bundled services were not to be offered then the sharing mechanism should be adjusted to reflect a reduction in revenues. In this case, ratepayers would have a guarantee of $4.5 million, with the next $1.3 million going to the account of the shareholder. From that amount, O&M, estimated to be $700,000, would be deducted, leaving $600,000 as the net share to the shareholder. Any gross margin above the aggregate of these amounts would then be shared at a 75/25 ratio, with the 75% going to ratepayers. The Company states that bundled transactions make up about 58 percent of the total Transactional Services gross margin. Therefore their proposal to reduce the ratepayer guarantee from $8 million to $4.5 million if bundled services are discontinued represents a benefit to the ratepayer since it equates to only a 43 percent reduction in the gross margin, rather than the full 58 percent.

Positions of the Intervenors

2.4.4 Most of the Intervenors stated that the intent of the current sharing mechanism was to provide an overall 75/25, ratepayer/shareholder benefit for gross margin and therefore shared CAC's perspective that a continuation of the current sharing mechanism would involve embedding 75% of the current forecast in rates, allowing the shareholder to recover the next 25%, with the remainder subject to a 75/25 sharing. Given that the current TS revenue forecast for 2005 is $15 million, CAC submitted that $11.25 million should be embedded in rates, with the next $3.75 million going to the shareholder, and the 75/25 sharing mechanism would apply beyond that. Several Intervenors stated that the discontinuance of bundled transactions should not impact the sharing mechanism. CAC did accept that, if the Board should deny EGDI's request to pursue bundled commodity transactions, the amount embedded in rates should be adjusted to reflect a reduced forecast of gross margin.

2.4.5 SEC argued that the previous sharing mechanism was initially based on a split of 90/10 in favour of the ratepayers, and after that the split became 75/25. As a compromise between the 75/25 and 90/10 position, SEC suggested that $12 million be embedded into rates, with the next $4 million going to the shareholder and the remainder subject to a 75/25 sharing mechanism.

2.5 BOARD FINDINGS

2.5.1 The Board has decided that it is inappropriate for either EGDI, or EGS as an agent of EGDI, to acquire gas commodity to be bundled with utility assets, thus creating bundled products. The Board directs the Company to refrain from this activity within 60 days of issuance of this Decision.

2.5.2 The Board does not decide casually to forego the opportunity to reduce distribution rates; however, the Board acknowledges the legislative and regulatory efforts in Ontario to create competitive markets for natural gas commodity. While the physical delivery of gas is a natural monopoly, storage and transportation services could reasonably be provided by competitors. One of the key developments in this evolutionary process has been the unbundling of supply, storage and transportation services by local distribution monopolies.

2.5.3 The Company's request in this application for authorization to conduct bundled transactions in its own name is contrary to this direction in regulation and public policy. The practice it has followed in the past two years, where its affiliate has had exclusive access to surplus storage and transportation assets and has bundled those assets with commodity for sale in the ex-franchise market is also inconsistent with the development of a viable competitive market for these services. The Board notes that this practice was inconsistent with the terms of the agency agreement between EGDI and EGS that has been filed with the Board.

2.5.4 The Board agrees with Direct Energy that commodity is the subject of a competitive market, and allowing a monopoly product to be bundled with it has the potential to undermine competition. The Board is particularly concerned with the lack of transparency in these transactions that results in opportunities for EGDI and EGS that are not available to other market participants.

2.5.5 Some Intervenors argued that the bundled commodity transactions should be allowed because they provide a financial gain to ratepayers. The Board disagrees, both because of the competitive impact discussed above and because of the increased risk to ratepayers. The Board agrees with EGDI that the parties who share in the margin from the activities should also share in the credit risk. The Company gives conflicting evidence on the projected costs of these risks suggesting on the one hand that they are small, and yet asserting that an annual cost of $2 million is appropriate for notional credit cost recovery. For the Board, this provides an additional argument that commodity transactions should not be undertaken on behalf of EGDI, either directly or indirectly. It is inappropriate, as argued by Energy Probe, for the Company (and its ratepayers) to take on a significant and material change to the Company's risk profile in order to engage in these functions.

2.5.6 In this situation, where the Company is not engaged in bundled commodity transactions, the Company has proposed a sharing mechanism such that the ratepayers would have the guarantee of $4.5 million, the next $1.3 million above that would be to the account of the shareholder (less O&M costs). Any gross margin above the aggregate of these amounts would then be shared 75/25 percent in favour of the ratepayers. The Company based this calculation on the fact that in the past year, bundled transactions made up more than 50% of the total TS gross margin and the assumption that most of this margin will be lost without bundling. Some Intervenors take the position that unbundled TS gross margin continues to increase and, based on the Company's numbers, the budget should be in the range of $15 million, and the ratepayers guarantee should be $11 to $12 million. Some other Intervenors agreed that the budget should be reduced if bundled Transactional Services were not allowed.

2.5.7 The Board notes that the appropriate sharing mechanism for Transactional Services should be based on a reasonable and well-defended gross margin budget, 75% of the budget guaranteed to the ratepayers, the next 25% to the account of the shareholder who deducts O&M costs, and the remainder shared 75/25 percent in favour of the ratepayers. The Board finds that there is little clear evidence supporting the position of any party on the appropriate budget due to the lack of transparency and clarity in the details of the bundled transactions. A breakdown of the portion of gross margin attributable to commodity versus surplus TS assets was not available. Although the Company had anecdotal evidence that some surplus assets could not be utilized without a commodity component, there was no direct evidence as to the extent of this impact. The Board does not accept that the Intervenor proposed budget of $15 million can be achieved without commodity included in the transactions. However, the Board also does not accept that a greatly reduced budget of $5.8 million as put forward by the company is appropriate. The Board therefore finds that the Transactional Services sharing mechanism will remain unchanged at a budget of $10.7 million. The ratepayers will have a guarantee of $8 million of the gross margin, and the next $2.7 million above that will be to the account of the shareholder (less O&M costs). Any gross margin above the aggregate of these amounts will then be shared 75/25 percent in favour of the ratepayers.

2.5.8 It is the Board's view that if surplus transportation and storage assets, which form the basis for the Transactional Services, were made available or promoted on an open market basis to any and all interested and capable parties, commodity bundled transactions could be developed in the market. Accordingly, the Board expects the Company to develop a methodology for making such surplus assets known to, and available to, unrelated market participants on a non-discriminatory basis as soon as practicable and ideally within 60 days. This methodology should be developed with the input and participation of market participants interested in having access to such assets. The Board expects that EGS, acting on its own behalf, could be an active participant in this market, but it is imperative that there be fair, equitable and open market opportunities for others. The costs associated with management of risk in these transactions would be an integral part of the bid process for all participants.

2.5.9 On or before January 31, 2005, the Board expects the Company to provide:

i) Confirmation that commodity transactions on behalf of EGDI have ceased; and

ii) A status report on the development of a methodology aimed at providing interested parties with fair and non-discriminatory access to surplus utility assets with the objective of optimizing the value of those utility assets.

3. GAS, TRANSPORTATION AND STORAGE COSTS (ISSUE 5.1)

3.1 BACKGROUND

3.1.1 Issue 5.1 deals with the Enbridge proposal to reflect in 2005 rates the cost consequences of a new storage contract negotiated with Union.

3.1.2 An agreement for Union to provide storage at cost-based (M12) rates to the Company was filed with the Board under docket number EBO 90 (June 16, 1978) and amended under docket number EBO 150 (September 9, 1988). The Company's view was that this contract would not expire until March 31, 2006.

3.1.3 However, the Company stated that Union's position was that the existing contract would expire March 31, 2004. The Company indicated that it began negotiating with Union for a new contract in 2003, in an effort to avoid the possibility of litigation.

3.1.4 The Company and Union reached agreement on a contract for 19.9 bcf of storage covering the period April 1, 2004 to March 31, 2014. The market-based rates in the new contract exceed the cost-based rates in the existing contract during the overlapping period, April 1, 2004 – March 31, 2006.

3.1.5 Union submitted the new contract to the Board for approval on February 25, 2004. On April 1, 2004, under docket number RP-2004-0137, the Board approved the parties to, the period of, and the space that was the subject of the new contract.

3.1.6 The Company has requested that the Board now approve the cost consequences of the new contract for ratemaking purposes. For the 2005 Test Year, the Company has included the costs of the new contract, which are estimated to exceed cost-based storage services by $2.7 million. For the period April 1, 2004 to September 30, 2005, Union's charges to EGDI for storage services under the new market-based rates are estimated to exceed the charges at cost-based rates by approximately $5.1 million.

3.1.7 The alternative to the Company receiving storage service under the new contract is for the Company to continue paying cost-based rates under the same terms as the existing contract until March 31, 2006, and proceeding thereafter under market rates to be negotiated. This contingency is specifically contemplated in the new contract. It provides that if the Board decides to not accept the cost consequences of the new contract for the purposes of rate making, that the parties, Union and EGDI would revert to the cost-based rates for the period up to March 31, 2006. The Company estimated that were the cost consequences of the new contract accepted by the Board, ratepayers would pay $11.4 million more in the first two years of the new contract, but would save an estimated $31 million over the following eight years. The Company estimated that the new contract would provide a ratepayer benefit of $11.855 million over the life of the contract in terms of net present value ("NPV").

3.2 POSITIONS OF PARTIES

3.2.1 The Board heard arguments opposing the Company's proposal from CAC, IGUA, Energy Probe, VECC, Direct Energy, SEC, and CME. These included:

- The upcoming Natural Gas Forum ("the Forum") will consider regulation of storage and transportation and will include a review of the merits of cost-based storage versus market-based storage. Board approval of the Company's proposal could predetermine the outcome of storage issues at the Forum;

- The Company's fear of potentially expensive litigation was not credible given the lack of any written communications attesting to the dispute over when the existing contract would expire;

- If the Company were to charge market rates rather than cost-based rates for all the storage it holds and contracts for, about 110 bcf, the additional cost would be approximately $76 million. For Union's and the Company's ratepayers combined, the additional cost could total up to $152 million;

- Storage is a provincial asset that should benefit Ontario ratepayers by being provided at cost-based rates. Until the Board concludes its upcoming review of storage in the Forum, the Board should not approve long-term contractual obligations. Otherwise the Board could be frustrated if its review concluded that Ontario gas utility customers should have access to storage at cost-based rates;

- The estimated future market prices for storage used to compare the new arrangements with the old are dubious as they were benchmarked against two bids that were untested. Further, the lack of disclosure of the details of these bids did not permit them to be tested in the hearing;

- The 10-year term of the agreement is inappropriate because it does not provide the Company with the requisite flexibility for a changing marketplace.

3.2.2 The Board also heard submissions by SEC and VECC that there was potential merit in the Company's proposal.

3.2.3 VECC submitted that the new contract is likely in the ratepayers' long-run interest because it is deemed to be below market. Also, if a storage arrangement were renegotiated later, the price of storage would likely be higher. VECC proposed that 2005 ratepayers should pay only cost-based rates and the difference between cost-based rates and the rates in the new contract should be recorded in the transportation and storage deferral account.

3.2.4 SEC argued that the Board's decision on this issue should depend on the likelihood that the Board will allow Union to charge the Company market rates beginning in 2006. If the Board does allow Union to charge the Company market rates beginning in 2006, the new contract would result in a net saving to the Company's ratepayers of $23.4 million with an NPV of $11.9 million. In this case, the Company's proposal should be approved. However, if the Board were to require Union to charge the Company cost-based storage rates, rejection of the proposal would save the Company's ratepayers $59.3M.

3.2.5 The Board also heard the Company's responses to these objections:

- There was no reason to believe that at the Forum, the Board would consider issues previously decided. There was also no indication that the Forum would be used to review Board approved storage contracts or whether Ontario storage users should have access to cost-based storage rates;

- In its EBRO 494/03 Decision, the Board approved market rates for some ex-franchise storage contracts and warned M12 customers, all of which were Canadian distribution companies, that they might face market-based rates for storage used to serve their own in-franchise requirements. The Board noted that the distribution companies had based their rates on having access to Union's cost-based rates and stated that the distribution companies "... should be provided an opportunity to make necessary adjustments to supply arrangements ...";

- The Board has approved a storage contract arising from an open season bidding process between Union and Utilities Kingston that resulted in Kingston end-users paying market storage rates;

- The RP-1999-0017 Decision with Reasons approved the renewal of Union's ex-franchise storage contracts at market rates;

- The Board's regulation of storage rates should not be suspended pending the outcome of the Forum. The Forum's purpose is to explore alternative regulatory policies and not to debate fact-specific issues or contracts. As such, approving the cost consequences of the Company's storage contract with Union does not impede the Board's ability to explore policy options at the Forum;

- If the Board does allow Union to charge market based storage rates in 2006, the Company's proposal provides net savings to ratepayers. The Company added that all management decisions should be presumed to be prudent unless challenged on reasonable grounds;

- The RFP process undertaken by the Company to obtain the storage would comply with the Board's requirements even if an affiliate had won the contract to provide storage. Further, the two rejected bids were similar in price; and

- The Board has approved: the parties to, period of, and the storage space of the 10-year contract under file number RP-2004-0137 on April 1, 2004, following a public proceeding.

3.3 BOARD FINDINGS

3.3.1 The question before the Board is not whether existing M12 cost-based storage contracts may be renewed at market rates. The Board's RP-1999-0017 Decision with Reasons allows that. The issue is whether the Board should accept for ratemaking purposes the new market-based storage rates provided for in this new contract, or whether the Board should require the Company to continue with the existing cost-based storage rates until 2006.

3.3.2 The Board finds that the Company's estimate of ratepayer benefits under the new contract is speculative because the Company has filed no evidence with respect to a publicly available competitive price for storage services for 2006 and beyond. Instead, the evidence supporting the claimed net ratepayer benefit relies upon very uncertain estimates. The Board is concerned with the lack of detail and transparency in the RFP process that underpinned the negotiated Union price. Given the lack of supporting evidence, the Board is unable to accept the Company's claim of ratepayer benefits under its proposal.

3.3.3 The new contract indicates that rejecting the Company's proposal would trigger a reversion to terms existing in the prior contract for the period April 1, 2004 to March 31, 2006, and this reversion would result in storage costs reduced by $11.4 million for the Company's ratepayers over this period.

3.3.4 Therefore, the Board denies the Company's request for recovery of the cost consequences of the new contract because of the uncertainty of long-term net benefits of the new terms versus the certainty of the short-term benefits under the existing terms.

4. RISK MANAGEMENT (ISSUE 5.2)

4.1 BACKGROUND

4.1.1 In the 2003 rate case Settlement Agreement, the Company committed to have an independent third party consultant, RiskAdvisory, review the Company's Gas Supply Risk Management Program. At issue in this proceeding are the proposed changes to the risk management program to reflect the RiskAdvisory recommendations.

4.1.2 The Company proposed the following changes to its risk management program:

- Removing the 10 percent restriction on hedgeable volumes to reduce the time frame over which the volumes can be hedged;
- Hedging volumes on a rolling 12-month basis to reduce price volatility to allow continual hedging and earlier hedging;
- Reducing the execution window to two days for AECO transactions and three days for Chicago transactions;
- Updating the Agency Agreement to reflect Company pre-approval of modifications to the model;
- Documentation of the segregation between trading functions within EGS;

- Periodic audits of EGS to ensure compliance; and

- Updating the risk management manual to reflect the primary objective of reducing price volatility, to restrict discretion, to align benchmarking with the primary objective, to change references from the Company trader to the Company approved trader, and to reflect the composition of the Gas Supply Risk Management Committee.

4.1.3 The Company also proposed to undertake a customer survey to update the $35 price volatility tolerance level identified in the surveys undertaken in 1994 and 1995. The cost of the survey, estimated to be in the range of $80,000, would be recovered through the PGVA. Aside from this one-time customer survey cost, the Company stated that there are no incremental costs associated with the Company's proposed changes.

4.2 POSITIONS OF PARTIES

4.2.1 The Board received submissions from VECC, Direct Energy, SEC, Energy Probe, and CME. Collectively, and in summary form, the Intervenors' substantial arguments are set out below:

- The Company's current risk management program is sound and requires no substantive changes;

- No changes should be made now because changes might preempt decisions made in the Natural Gas Forum (the "Forum");

- The Company's proposals would dampen price signals and reduce energy conservation;

- The goal of price stability, without the goal of purchasing commodity at the lowest cost, would be to the detriment of ratepayers;

- Decreasing price volatility will mute price signals to consumers and will interfere with fostering a competitive market by reducing the attractiveness of a marketer's fixed-rate offering;

- The proposal to eliminate the 10 percent threshold for hedgeable volumes would allow hedging all hedgeable volumes in one day, increase risk to ratepayers due to decreased diversification, and involve a significant expansion in the hedging program that would dampen price signals. This proposal would be more appropriately addressed in the Forum;

- The proposal to move to a rolling 12-month hedging year should not be approved, but should be deferred until the associated changes to the QRAM methodology have been addressed. The Company has filed no evidence about this proposal. Further, it would move costs outside the time periods in which gas deferral balances are cleared, thereby reducing the ability of customers to make timely decisions in comparing utility rates to market rates;

- The risk tolerance survey should not be undertaken now because the upcoming Forum will consider the future of system supply. However, if the Company were to undertake this study in 2005, it should do so within the O&M budget agreed upon in the 2005 Settlement Proposal and not recover the survey costs from the PGVA, because the PGVA was intended to recover gas cost variances;

4.2.2 The Board notes VECC's support for narrowing the execution windows to reduce the execution time thereby reducing "lost opportunity" concerns.

4.3 BOARD FINDINGS

4.3.1 In the Board's view, the issue before it as originally framed was a review of the RiskAdvisory report and the Company's response to its recommendations. The Board notes that all parties to the previous rates proceeding agreed with the choice of consultant and the scope of the task.

4.3.2 The Board also notes that there was little cross-examination questioning the advisability of RiskAdvisory's recommendations. Any disagreements were largely based on the concept of a utility risk management plan *per se*, and not on the specific proposals for change to the existing plan.

4.3.3 The Board notes the evidence that only one major Canadian gas utility does not have a risk management plan. The Board also notes the evidence that no utility that had adopted a risk management plan, had ever subsequently discarded its plan.

4.3.4 The Board views the proposals before it as improvements to an existing program that has provided value to ratepayers. No Intervenor argued that the Company should discontinue the risk management program at this time. The Board is not convinced by arguments that future policy considerations for change should rule out current improvements to an existing program. Any future changes that may occur would be implemented by the Board based upon the environment at the time of change.

4.3.5 There was no evidence in this proceeding that the proposed changes represented a wholesale policy shift or would adversely affect any party. The proposed changes are more about adjustments in methodology.

4.3.6 The Board accepts the Company's evidence that there would be no increased risk for ratepayers. In the Board's view, there is no evidence to support the assertions made by some parties that adopting the Company's proposals would negatively impact the competitive markets. The Board is not persuaded that these added controls on volatility will have a significant impact on the competitive market.

4.3.7 The Board's findings with respect to the specific components of the Company's proposal are given below. The Board notes that the proposals before it in this proceeding do not include all the recommendations in the RiskAdvisory report. The Board expects the Company to make another application to the Board if it wishes to implement any other recommendations contained in the RiskAdvisory report, or if it wishes to make any other changes to its risk management program.

4.3.8 The Board accepts the Company's submission that an appropriate goal of a risk management program is to reduce price volatility and approves the proposal to make this the primary objective of the Company's risk management program.

4.3.9 With respect to removal of the 10 percent restriction on hedgeable volumes, the Board notes that the Company's expert witness testified that "the 10 percent restriction on volumes is more conservative than they have seen elsewhere". The Board also notes that the changes suggested in the RiskAdvisory report were intended to enhance performance of the Company's program in reducing price volatility. The Board therefore approves removal of the 10 percent restriction on hedgeable volumes.

4.3.10 With respect to the rolling 12-month hedging period, the Board has concerns as to how the Company will make this proposal fit with its QRAM methodology, yet to be proposed. Also, the Board believes that where possible, costs should not be shifted outside of the period of their incurrence. However, the Board notes the evidence that similar concerns did not exist with respect to the hedging and QRAM policies of Union Gas, which, the Board notes, has adopted a rolling 12-month QRAM plan. The Board conditions its approval of a rolling 12-month hedging period on the Company filing with the Board for approval, within 60 days of this Decision, a revised QRAM methodology that addresses the concerns of the Board and Intervenors and which is appropriate for the rolling 12-month hedging period.

4.3.11 The Board approves the Company undertaking a customer survey in 2005 as proposed. However, the Board does not agree with the Company's proposal to recover the incremental costs of the survey through either an increase in approved O&M or by deferral account treatment. Given the modest estimated cost of the survey, the Board believes that the Company can manage this cost within its existing budget.

4.3.12 Regarding the narrowing of the hedging execution windows, the Board accepts the Company's proposal, as the Board believes it will reduce lost opportunities.

4.3.13 With respect to the other changes to the risk management program proposed by the Company in this proceeding, including manual and agency agreement updates, the Board notes that no substantive arguments were raised opposing these changes. In these matters, the Board accepts the Company's evidence, including RiskAdvisory's recommendations, and approves the changes as proposed.

5. DEFERRED TAXES (ISSUE 12.1)

5.1 BACKGROUND

5.1.1 The Board has been asked to rule on what amount should be recoverable from ratepayers following the Board's RP-2002-0135 Decision and Order on deferred taxes dated December 3, 2003 (the "135 Decision"). In the 135 Decision, the Board found that the Company is entitled to recover an amount from the notional utility account, as follows:

> "The Board finds and orders that EGDI is entitled to recover from the notional utility account an amount, after taxes, equal to the deferred taxes that became payable between October 7, 1999[1] (the date in which the assets were transferred out of EGDI to an affiliate) and May 7, 2002 (the date of the sale of the rental assets to a third party). EGDI may seek to recover such amount, appropriately verified, in its next rates application. The Board expects EGDI to ensure that its request for recovery includes consideration of any potential for rate shock." (135 Decision, para. 62)

[1] It appears that the date should have been written as October 1, 1999 rather than October 7, 1999. Parties to the RP-2003-0203 proceeding have assumed that October 1, 1999 was the correct date.

5.1.2 In response to the Board's finding and order, the Company filed evidence in support of a claim of $23,873,850 ("$23.9 million"), after taxes, to be recovered over a two-year period starting in fiscal 2005. The Company stated that the $23.9 million represented the amount of deferred taxes that became payable during the period October 1, 1999 and May 7, 2002 in relation to the transferred rental assets that were resident in 3696669 Canada Inc. ("Rentco"). Rentco had been established for the purpose of holding the transferred rental assets after the Utility unbundled its ancillary programs on October 1, 1999.

5.1.3 The rental program deferred taxes matter has a lengthy procedural history. The Board has issued two key decisions on the matter. The first was the E.B.O. 179-14/15 Decision dated March 31, 1999 (the "179 Decision"). The second was the 135 Decision.

5.1.4 The Board will refer only to those parts of the historic record that are relevant to the current issue in this case, that being the amount of deferred taxes recoverable. In other words, the Board does not intend to embark on a lengthy description of all the events leading up to this decision. Anyone wishing to refer to the full record can access it through dockets E.B.O. 179-14/15, RP-2002-0135 and the current proceeding, RP-2003-0203.

5.2 POSITIONS OF THE PARTIES

5.2.1 The Company's position is summarized as follows.

- Prior to the unbundling of the group of ancillary programs on October 1, 1999, the gas utility owned a group of rental assets. At that time, the Utility's business activity of renting this group of assets was referred to as the "rental program," and it was determined by the Board to have provided benefits to gas ratepayers through lower gas distribution rates in the amount of $50 million.

- At the same time, the Company was aware that a significant amount of unrecorded deferred taxes had accumulated in respect of this group of assets. In the 179 Decision, the Board decided that by way of the notional utility account, recognition should be given to the benefits provided to gas ratepayers and that up to $50 million could be drawn from the notional utility account to pay deferred taxes as they became due.

- EGDI interpreted the Board's 179 Decision as referring to the benefits provided by the group of rental assets held in the Utility prior to unbundling, and further that when the Board spoke of deferred taxes becoming due, it was referring to deferred taxes in respect of that same group of rental assets.

- The Company's view was that with a particular group of assets such as the group of rental assets that were formerly owned by the Utility, the amount and timing of the deferred taxes becoming payable can be calculated by comparing book depreciation to capital cost allowance.

- The Company asserted that the calculation is not complicated and that the amount of deferred taxes that became payable between October 1, 1999 and May 7, 2002 was $23.9 million. EGDI emphasized that this was the amount in respect of the particular group of rental assets, referred to as the utility's rental program.

- In the Company's view, no party has cast any doubt on the $23.9 million, or pointed out any obfuscation in the Company's presentation of the figure.

- The Company also asserted that the $23.9 million in deferred taxes payable is entirely consistent with all of the decisions that the Board has issued on the deferred taxes subject to date.

5.2.2 Intervenors making submissions included CAC, CME, Energy Probe, IGUA, SEC and VECC. These parties advanced a number of arguments with respect to the appropriate amount for recovery from ratepayers. The arguments included various interpretations of Board decisions and of alternative approaches to the treatment of taxes. Collectively, and in summary form, the Intervenors' substantial arguments are set out below:

- They argued that the rental business being carried out in Enbridge Services Inc. ("ESI") and Rentco should be treated as one enterprise for the purposes of determining the deferred tax amount because in practice, it is a single business. Before it was sold to Centrica plc, the ESI business was being operated as an ongoing business with new asset additions while the Rentco business contained a static pool of assets. With no asset additions, the deferred tax crossover was achieved at an artificially early date within Rentco.

- The Board should ensure that ratepayers get credit for the $42 million tax refund that the Board directed to the shareholder's account in its 179 Decision.

- The Board should consider the recovery amount in the context of the actual taxes paid by Rentco, which was about $10.9 million. The actual taxes paid should constitute a cap on the recovery amount.

- The Board should ensure that ratepayers get credit for tax savings, outlined in the ESI tax plan that were ignored so that ESI could save $2.7 million in capital taxes. Those tax savings were identified to have been $11 million.

- Intervenors also argued that the Board should take into account the gain from the sale of the rental business to Centrica plc, because the Board specifically mentioned the prospect of a sale to a third party as a potential outcome in its 179 Decision. In view of the fact that the gain from this sale overshadowed the deferred tax recovery, the Board should therefore apply the proceeds in its consideration of any recovery.

5.3 BOARD FINDINGS

5.3.1 In previous proceedings the Board has already heard and decided a number of the substantive arguments put forward by Intervenors in connection with the deferred taxes issue. What is different this time is that the Board has the advantage of historic financial data.

5.3.2 The key decisions or principles set out in past Board decisions that are relevant to the question of the amount of deferred taxes payable by Rentco are set out below:

1) The Company may seek to recover up to $50 million to pay deferred taxes associated with the rental program assets as they become due. (179 Decision, para. 3.3.19) The Board confirmed this in the 135 Decision, para. 59.

2) The $42 million credit arising from the Supreme Court's 1998 decision on expensing versus capitalizing the rental program installation costs belongs to the shareholder. (179 Decision, para. 3.3.11)

3) The Board accepted that the deferred taxes payable should be assessed from the perspective of Rentco alone, and not in combination with other affiliated companies. (135 Decision, para. 60)

4) The Board confirmed the entitlement of the Company to collect the deferred taxes that became payable for Rentco between the relevant dates. (135 Decision, para. 62)

5.3.3 The Board has carefully considered all of the evidence put forward by the Parties on this issue. The Board relies on the guidance provided in past decisions on this subject and this guidance fundamentally settles much of what is being disputed. Although the Board is not bound by previous decisions, they have a high degree of persuasive value. Many of the arguments put forward in this case are either subsumed or become irrelevant if these previous decisions are relied upon and applied.

5.3.4 The Board is not convinced that the additional evidence available in this proceeding would have caused a different outcome in the 135 Decision or the 179 Decision had it been available at that time.

5.3.5 Nevertheless, the Board believes that it would be instructive to provide additional clarity on three points, namely, the combination issue, the gain on the sale of the business issue, and the issue respecting the $42 million tax credit.

5.3.6 Confirming the 135 Decision, the Board finds that it is not appropriate to consider the tax deductions contributed by other affiliates as an offset to the taxes payable by Rentco. The ratepayer was not entitled to benefit from the tax deductions attributable to affiliate losses, since those tax deductions were not related to the rental program and the parent could have chosen a different time or way to capture them. In the specific case of the $11 million tax savings, outlined in the ESI tax plan as referred to by SEC, the Board is further comforted by the Company's evidence that the $11 million savings was only a matter of timing and that there were no permanent savings available from that transaction.

5.3.7 The second point for clarification is the treatment of the gain on the sale of the business to Centrica plc and whether that gain should be considered in reducing, or eliminating, the deferred taxes payable. The Board has decided that a reduction is not appropriate because the Board's 135 Decision confirmed the entitlement of the Company to collect the deferred taxes. The Board made its decision in the 135 case with full knowledge of the Centrica plc transaction, and chose to confirm the Company's entitlement to a draw from the notional utility account notwithstanding the same.

5.3.8 Intervenors argued that the $42 million tax credit should not be allocated to the shareholder because the liability had been transferred to the new owner of the assets as a result of the sale. The 179 Decision established that the shareholder was responsible for the overall deferred tax liability. The Board notes that the recovery of the deferred taxes payable from October 1, 1999 to May 7, 2002 does little to reduce this liability. The fact that future liability for deferred taxes was transferred with the sale of the rental assets to a third party is irrelevant as, presumably, this liability impacted the sale price. Therefore, the Board confirms that the $42 million tax credit belongs to the shareholder.

5.3.9 In view of guidance provided in past Board decisions, the only question left for the Board is to determine then, is what amount represents "the deferred taxes that became payable" between the two relevant dates.

5.3.10 The Board finds that the Company has complied with the guidance provided by the Board in the 179 Decision and the 135 Decision. Further, the Board finds that the Company's actions were reasonable in view of the Board's directives.

5.3.11 In the Board's opinion, none of the intervening parties was able to credibly refute the calculation of the $23.9 million as being the number "equal to the deferred taxes that became payable" between the two relevant dates, and that was ordered by the Board in the 135 Decision. The Company outlined its methodology in some detail in its prefiled evidence.

5.3.12 It appears to the Board that the $23.9 million figure accurately represents "the deferred taxes that became payable between October 1, 1999 (the date in which the assets were transferred out of EGDI to an affiliate) and May 7, 2002 (the date of the sale of the rental assets to a third party)". The Board therefore finds that the Company is entitled to collect $23.9 million from its ratepayers.

5.3.13 The Company may recover $23.9 million, after taxes, in equal installments, over a three-year period commencing in fiscal 2005. The Company shall not recover interest on the balance in 2005, but may do so for the residual balance in future years. However, any interest recovery is applicable only to $23.9 million which represents the after tax amount. The Company is hereby authorized to set up a deferral account for this purpose.

5.3.14 The Board finds that the three-year recovery period is appropriate to mitigate rate shock and to match the roughly three-year period in which the deferred taxes payable were generated.

5.3.15 The Board considers that this ruling on the recovery amount brings finality to this issue.

6. FISCAL YEAR-END CHANGE

6.1 BACKGROUND

6.1.1 The issues in this chapter, Issues 13.1 and 13.2, focus on the Company's proposal to change its fiscal year-end from September 30 to December 31 and the specific impacts associated with the change. The Company's reason for the change is to bring its fiscal and reporting periods in-line with that of its parent, Enbridge Inc.

6.1.2 The Company's 2005 rate application was framed as a cost-of-service application for a 12-month period from October 1, 2004 to September 30, 2005. To accommodate the change in year-end, the Company has sought Board approval for distribution rates for the period October 1, 2005 through December 31, 2005 (the "Stub Period"). The Stub Period would provide a bridge to the first complete year in the new fiscal year-end structure, commencing on January 1, 2006 and ending on December 31, 2006.

6.1.3 The Company has requested that the rates for the Stub Period be determined by applying an indexing mechanism, consisting of 90% of the change in the Ontario Consumer Price Index ("CPI"), to the approved rates for the 2005 Test Year. The Company described the proposed methodology as identical to the one used to set rates for the 2004 Test Year and which was approved by the Board in its RP-2003-0048 Decision.

6.1.4 Distribution rates for fiscal 2006, January 1, 2006 to December 31, 2006, would be established by a separate rate application.

6.1.5 The Company made specific recommendations on other ancillary issues arising from the change in fiscal year-end. They are addressed separately in this chapter and include: the amount of an increase in the Stub Period; processing deferral accounts and the PGVA; administering Transactional Services earnings sharing; the handling of the DSM plan; the implementation of cost allocation changes for upstream storage and transportation as a result of a different year-end.

6.2 PROPOSAL TO CHANGE YEAR-END FROM SEPTEMBER 30 TO DECEMBER 31, 2005

Position of the Company

6.2.1 The Company described the change in year-end as having no impact on earnings, and being neither a benefit nor disadvantage to either shareholder or ratepayer. The Company also asserted that it would not be appropriate for the proposed change to result in any detriment to the shareholder, since the change in year-end is solely for the purpose of improving the clarity of financial reporting within the Enbridge group of companies.

6.2.2 The Company stated that the change in year-end will result in no incremental costs to the Company and that the costs associated with the minor modifications to the Company's reporting systems will be outsourced and borne by the shareholder. There has been no dispute about either the Company's right to change its fiscal year-end, or the use of the Board approved rates for the Test Year as the basis for consideration of rates in the Stub Period.

Board Findings - Changing the Fiscal Year-End

6.2.3 The Company's right to change its fiscal year-end reporting date was never questioned in the proceeding.

6.2.4 The Board does not see itself as having an approval role in the decision to change fiscal year-ends, but it does recognize that Board approval is required to implement the transitional changes that result from the corporate decision to change the reporting period.

6.2.5 The remainder of this chapter will concentrate on the issues that arise out of the Company's decision to change its year-end from September 30 to December 31, in 2005.

6.3 PROPOSAL TO INCREASE RATES FOR THE STUB PERIOD OF OCTOBER 1, 2005 TO DECEMBER 31, 2005

The Position of the Company – Stub Period Rate Adjustment

6.3.1 The Company proposed that the rates for the Stub Period be determined by applying an indexing mechanism, consisting of 90% of the change in the Ontario Consumer Price Index ("CPI"), to the approved rates for the 2005 Test Year. The increase in forecast revenue at existing rates resulting from the application of this proposed mechanism was estimated to be $4.5 million.

6.3.2 To demonstrate that some type of increase was required, and that 90% of the CPI was a reasonable proxy for a more rigorous rate setting process, the Company filed cost-of-service information based on a 12-month period from January 1, 2005 to December 31, 2005. The Company compared that data to the detailed information covering the 12-month period October 1, 2004 to September 30, 2005 included in this Application, and found the results to be very close to the indexed approach. The Company described drivers such as: inflationary pressures; customer growth; and increasing cost of employee benefits.

6.3.3 The Company's witnesses responded to Intervenor probing about alternate methodologies for calculating rates for the Stub Period, by stating that they were unaware of any methodology to determine rates for either a 15-month or a 3-month period. They explained that this was due primarily to an inability to calculate utility rate base and ROE using the Board's formula, on any period other than a 12-month period. The Company witnesses asserted that, in a seasonal business, it would be quite inappropriate to apportion ROE, which has been calculated on the basis of 12 consecutive months, to a different period such as 3-months or 15-months. The Company witness added that it is not advisable to set rates on a quarterly basis, unless each quarter were a fully scalable version of the annual year, and that is not the case for a weather-sensitive utility.

6.3.4 The Company provided further evidence showing that shareholder retained earnings over the long-term, when the Board approved ROE is applied to the Stub Period, did not increase. Conversely, applying something less than the Board-approved ROE showed a lower, long-term earning opportunity for the Company, when measured on the basis of retained earnings.

6.3.5 The Company's position was that the Company and ratepayers should be equally unaffected by a change in the fiscal year-end, a change which is merely a change in the reporting period. It does not reduce profits available for distribution to shareholders, nor does it increase them, and the value of the business or service to customers is unaltered.

6.3.6 The Company described its approach to the Stub Period rate change as pragmatic and fair.

Position of the Intervenors-Stub Period Rate Adjustment

6.3.7 The Intervenors' position with regard to Issues 13.1 and 13.2 were described in the Settlement Proposal as follows:

> "The equity risk premium method upon which the Board's Equity Return Guidelines are based produces an annualized allowed equity return for Enbridge Gas Distribution of about 9.69%. Without the inflationary increase in rates which Enbridge Gas Distribution seeks for the period October 1, 2005, to December 31, 2005, which Intervenors oppose, Enbridge Gas Distribution's forecast annualized ROE for the 15 months ending December 31, 2005, would be about 11.0%, representing an excess of annualized equity return of about 1.3% over the Company's applied-for Test Year percentage of about 9.69%. The forecasted over-earnings

> adjustment to which ratepayers claim to be entitled is a pre-tax amount of about $30 million. Enbridge Gas Distribution's fiscal year-end change from September 30 to December 31 must be accompanied by an equity over-earnings adjustment without which ratepayers will never recover the extent to which Enbridge Gas Distribution's forecast annualized equity return for 15 months exceeds the Guideline Equity Return."

6.3.8 Intervenors, including CAC, CME, VECC, Energy Probe and IGUA, relied largely on cross-examination of Company witnesses and argument to assert that the Company's proposal would generate, by design, excess over-earnings when the Board-approved ROE is applied to a three-month Stub Period, from October to December, in which rates historically over-collect compared to costs.

6.3.9 Intervenors requested that the Board apply various methods to generate a cost of service rate-making analysis to clearly determine Company over-earnings during the Stub Period.

6.3.10 IGUA argued that there would be an additional over-recovery as a result of the Company's over-recovery of costs in the Stub Period. IGUA asserted that the October 1 to December 31, 2005 period would recover some of the costs of service that the Company will incur later, in weak quarters. Since 2006 test year rates will be established to enable the Company to recover all of the reasonable costs it forecasts to incur between January 1 and December 31, 2006, it follows that the Company's 2006 test year rates will recover some costs already being recovered in the Stub Period rates. IGUA proposed a remedy to recover any portion of the costs that it incurs between April 1 and September 30, 2006 that was collected twice, once in Stub Period rates and again in 2006 test year rates.

6.3.11 SEC acknowledged that there was no long-term benefit to the shareholders using the retained earnings analysis relied upon by the Company and submitted that no one had been able to demonstrate or prove that, on a continuous basis, changing the fiscal year-end makes any financial difference to the company.

Board Findings- Stub Period Rate Adjustment

6.3.12 Two regulatory decisions involving changes in fiscal year-end were referenced in the hearing by the Company, one being Union Gas Limited's application to the Board, and the other being the Yankee Gas Services Company application to the State of Connecticut Department of Public Utility Control in January 10, 2001. Two consistencies were apparent in these decisions, first that no attempt was made to do a full cost of service rate calculation for the stub periods, and second that the rates in effect at the commencement of the stub period were left unchanged for the stub period.

6.3.13 While the Board understands Intervenor arguments that the three months comprising the Stub Period are among the highest return months that the Company enjoys in a normal year, the Board is not persuaded that the Company will derive any financial benefit as a result of the proposed change in year-end. In fact, the Company's evidence supporting the use of the Board-approved ROE, showed that its long term Retained Earnings will not change over time when using that ROE.

6.3.14 With respect to the merits of considering cost of service calculations to create rates for the Stub Period, Intervenors failed to negate the Company's argument that it would be very difficult and inappropriate in the circumstances of the Company's seasonally sensitive operations to attempt to impose an ROE on anything less than a 12 consecutive-month basis. The Board agrees that an entirely different approach to calculating ROE would have to be considered before it would be appropriate to apply the Board approved ROE to any period other than consecutive 12 months.

6.3.15 Convinced that Intervenor's requests for full cost of service analysis for either a 3-month or 15-month Stub Period is not appropriate in this case, the Board is left with the question of whether the proposed indexing methodology is appropriate.

6.3.16 The Board reviewed the findings in RP-2003-0048, which were referenced several times in this proceeding. In that decision, which involved the use of a CPI adjustment, the Board emphasized that the rate setting methodology accepted in that case was unique, and arose from a need to get the Company back on track with an appropriate regulatory schedule for filings. Neither the Intervenors nor the Board suggested abandonment of the general preference for rigorous regulatory oversight involving a detailed examination of utility costs.

6.3.17 In the case before us, the Applicant implied that the need to get back on a regulatory schedule in RP-2003-0048, had been sufficiently matched by the shareholder's need to change the Company year-end. The Board does not agree that this represents a "special circumstance" which justifies the use of the CPI adjustment factor, rather than a thorough and tested review of cost incurrence.

6.3.18 The RP-2003-0048 decision warned parties that the acceptance of the indexed CPI adjustment methodology should not be relied upon by Utility applicants as a predictor of Board acceptance in future applications. The decision further stated that the Board cannot accept proposed rates unless it is satisfied, on all the evidence, that those rates are just and reasonable. The burden of satisfying the Board that proposed rates are just and reasonable rests on the applicant.

6.3.19 In RP-2003-0048 the Company provided more statistical and historic evidence supporting the use of the annual CPI as a component in adjusting rates for that 12-month test year than was the case in the current proceeding. Even with the additional evidence, the Board was not prepared to grant an unconditional approval, and imposed an earnings-sharing mechanism to protect the ratepayer from potential over-earnings by the Company in the 2004 rate year.

6.3.20 The Board finds that the Company's evidence, supporting its assertion that costs would increase during the Stub Period, was not sufficient for the Board to determine an appropriate rate increase. The evidence supporting the use of an indexed CPI adjustment did not provide sufficient support to establish a reliable relationship between the quarterly CPI, and the changes in the Company's costs in the Stub Period.

6.3.21 The Board finds that the Company has not met its onus to provide sufficient evidence to support the use of the proposed CPI adjustment factor as a rate escalator for the Stub Period. Accordingly, the Board denies the Company's request for an increase in rates associated with the CPI index during the Stub Period, October 1, 2005 to December 31, 2005.

6.4 CHANGE IN YEAR-END - IMPACT ON DEFERRAL ACCOUNTS

6.4.1 The Company has proposed to clear deferral and variance accounts, which the Board deems appropriate for clearance as of October 1, 2005. Such accounts would be based on balances projected as of July 31, 2005. Any variances from those projected balances, and any amounts that would be accumulated in the October 2005 through December 2005 period, would be subject to the Board's review as part of its consideration of the Company's filing of actual and projected deferral account balances in subsequent QRAM filings. These balances would be disposed of in a manner determined by the Board at that time.

6.4.2 No substantive issues were raised regarding this proposed treatment of deferral and variance accounts. The Board finds the treatment acceptable except where modified in the following sections.

6.5 CHANGE IN YEAR-END - IMPACT ON PURCHASED GAS VARIANCE ACCOUNT ("PGVA")

6.5.1 The Company proposed to mirror the rate setting approach in its handling of this account for the Stub Period. The Company would clear the PGVA for the 12-month period from October to September in the normal course. For the three-month Stub Period, they recommend clearance based upon the materiality of any variance in the PGVA for the three-month period relative to what was forecast.

6.5.2 No substantive issues were raised regarding this proposed treatment of deferral and variance accounts. The Board accepts the Company's proposal.

6.6 CHANGE IN YEAR-END - IMPACT ON TRANSACTIONAL SERVICES SHARING MECHANISMS

6.6.1 Transactional Services are addressed in Chapter 2 of this Decision. However, changes in the Company's fiscal year-end prompt the requirement to establish a Board-approved methodology for administering these services and accounting for costs and revenues related to them during the Stub Period.

6.6.2 The Company proposed that the Transactional Services sharing methodology be extended for the Stub Period by prorating the gross margin and the ratepayer and shareholder amounts which the Board approves in this proceeding over the Stub Period and then applying the 75/25 percent split for any revenues in excess of the guaranteed amounts.

6.6.3 Although very little argument was directed to this matter, the Board notes that IGUA accepted that the Stub Period Transactional Services sharing mechanism should be based on 25 percent of the full-year Transactional Services mechanism, and that VECC accepted the pro-rata sharing proposal put forward by the Company.

6.6.4 The Board finds the Company's proposal to apply the Board's findings contained in Chapter 2 of this Decision to the Stub Period on a pro-rata basis to be fair and reasonable.

6.7 CHANGE IN YEAR END - IMPACT ON DSM

Background

6.7.1 The Board's findings regarding the 2005 Test Year DSM program were described in the Board's RP-2003-0203, Partial Decision with Reasons, issued August 31, 2004.

6.7.2 To determine the target and budget for the DSM program during the Stub Period, the Company proposes to set the amounts on the basis of 25% of the 76.9 million cubic metres annual target volume and the $14.8 million annual DSM budget established for the 2005 Test Year DSM program in the Settlement Agreement. This equates to a volumetric target of 19.2 million cubic metres and a total O&M budget of $3.7 million.

6.7.3 The Company stated that the proposed target of 25% of the annual volume was very aggressive based upon the fact that the four-year historic performance in the October to December quarter accounted for only 15% of the annual budget.

6.7.4 Included in the Company's proposal for the Stub Period are the following specific features:

- A savings allocation of 100 percent of the credit where they partner with other organizations to bring forward DSM programs.

- Use of the Shared Savings Mechanism ("SSM") and the Lost Revenue Adjustment Mechanism ("LRAM") and the Demand Side Management Variance Account ("DSMVA"), within the Stub Period on a prorated basis.

- The evaluation report and audit relating to the Company's DSM activities in fiscal 2005 will be expanded to include the three-month Stub Period. Fiscal 2005 and the Stub Period are considered as two discrete periods and will be presented in the report separately.

6.7.5 To address any perception of gaming of the 12-month and 3-month periods and to also protect the Company's interests, the Company proposed the following safeguards as criteria for evaluating the SSM, based upon three different scenarios:

- If the TRC savings are achieved in both the Fiscal 2005 and Stub Periods, the SSM is proposed to be based upon the aggregate of the volumetric targets in the two periods (12 + 3 months), calculated to be 96.1 million cubic metres.

- If the TRC savings are achieved in Fiscal 2005 but not in the Stub Period, the SSM is based upon the volumetric target in the 12-month Fiscal 2005 period only, agreed to be 76.9 million cubic metres.

- If the TRC savings are not achieved in Fiscal 2005 but they are achieved in the Stub Period, the SSM is based upon the aggregate volumetric targets in the two periods (12 + 3 months) calculated to be 96.1 million cubic metres.

Positions of the Parties

6.7.6 A number of Intervenors (CME, CAC, VECC and Energy Probe) opposed the idea of having two distinct volumetric targets that would be applied differently depending upon performance outcomes in the 12 and 3-month periods. They urged the Board to order the Company to adopt a 15-month approach to calculate the SSM.

6.7.7 Intervenor justification for the 15-month approach included:

- The Company should not be rewarded for a 12-month achievement where Stub Period underachievement would result in underachievement on a 15-month basis.

- The Company did not provide sufficient evidence to support its claim that the Stub Period target was aggressive.

- A 15-month time frame simplifies the evaluation and audit process.

6.7.8 CME took issue with the Company's proposal to include a savings allocation of 100 percent of the credit where it partners with other organizations to bring forward DSM programs. CME requested that the Board direct the company to increase the volumetric target for the Stub Period proportionately for purposes of calculating the incentive if the number of shared programs or the intensity of those shared programs increased.

6.7.9 The Company responded to these arguments by submitting that it would be unfair to penalize the Company by adding to the 12-month target a three-month Stub

Period target, when its evidence was to the effect that it will be challenging to achieve the stated goals, based upon historic performance in that 3-month period.

6.7.10 SEC supported the Company's two-part SSM structure as a good solution to this unusual and atypical situation. It suggested that reaching DSM targets is inherently desirable, and there is little harm that can come out of the Company's proposal.

6.7.11 Pollution Probe and GEC indicated their support of the Company's proposal for the *pro rata* extension of the budget and target already approved for the 12-month period.

Board Findings

6.7.12 A primary consideration guiding the Board is the achievement of an energy savings target and an associated incentive, both generally agreed upon by parties, using the most simple and most effective method possible.

6.7.13 The Board heard no evidence demonstrating any material harm in accepting the Company's proposal. Furthermore, the Board acknowledges the Company's efforts to address possible perceptions of "gaming".

6.7.14 The Board is not concerned about the Company partnering with others to accomplish TRC savings, based upon the goal of achieving the greatest possible DSM benefits at the lowest cost, and in the simplest way possible.

6.7.15 The Board is not convinced that any other proposal offered by any party was likely to generate greater TRC savings, at any lower cost, and considers the Company's proposal to be fair, practical and straightforward.

6.7.16 Accordingly, the Board accepts the Company's proposal, including the "safeguards" described as part of the Company's proposal, and orders the *pro rata* extension of the budget and target approved for the 12-month period be applied to the DSM volume target and budget be applied to the Stub Period.

6.8 CHANGE IN YEAR END IMPACT - UPSTREAM STORAGE AND TRANSMISSION COST ALLOCATION CHANGES

6.8.1 The Company has proposed that the Board adjust the plan to phase-in the cost allocation changes that were agreed by all parties and reflected in the Settlement Proposal. The Company's proposal is to move the effective date of the 3rd year of the 4-year phase-in, from October 1, 2006, to January 1, 2007.

6.8.2 The Company contended that the agreed upon phase-in plan did not anticipate the implications of a change in year-end. The plan calls for a four-year phase-in of the consequential higher costs to large-volume, T-Service customers, and the resultant lower costs to small-volume customers. The planned phase-in was to take effect on each October 1st of 2004, 2005, 2006 and 2007, respectively.

6.8.3 The Company described the proposed adjustment as providing a balance between fairness and administrative simplicity insofar as 80 per cent of the benefit to the small-volume users occurs primarily in the first two years of the phase-in and thereafter administrative simplicity outweighs the timing lag for the remaining benefits.

6.8.4 VECC noted that the phase-in plan had been agreed to by all parties in the Proposed Settlement and opposed the proposed change on the grounds that:

- The Company had full knowledge of the plan to change year end during the ADR process;
- The October to September adjustment for the rate design is a formulaic process that can be carried out either on January1 or October 1.
- The delay does not address fundamental problem of cross-subsidization between rate classes.

6.8.5 TransAlta asked that the Board be aware of the inconsistencies between fiscal years and phase-in years, and expressed the view that this was inconsistent with uniform ratemaking principles. The Board found no evidence to establish this as a material concern, and does not find it sufficient, by itself, to undermine the intent of the Settlement Agreement.

6.8.6 The Company has only offered "administrative simplicity" as a reason for making this recommended change to the Settlement Agreement. The Board believes that by its very nature, a change in fiscal year end is not administratively simple and the Company should be prepared to manage some complications in order to achieve its corporate purpose in establishing a new fiscal year-end.

6.8.7 The Board is reluctant to interfere with a Settlement Agreement resulting from an ADR process, and in this instance any change it makes to the 48-month phase-in will necessarily cause one ratepayer group to benefit and another to lose.

6.8.8 The Board is always prepared to consider cost efficiencies in weighing its decisions; however, in this case, the Company provided no evidence detailing the relative administrative costs of the proposed phase-in, versus that agreed to in the Settlement Proposal. The Board is therefore unable to evaluate the Company's claim that administrative simplicity outweighs the timing lag for the remaining benefits.

6.8.9 The Board therefore finds it appropriate to maintain the phase-in, as agreed to in the Settlement Proposal, starting on October 1, 2004 and ending on September 30, 2008.

7. RATE IMPLEMENTATION

7.1.1 The Board notes that the September 27, 2004 Interim Rate Order was based on a revenue requirement established as the outcome of the settlement of issues in the Settlement Proposal. The Interim Rate Order also reflects the Board's August 31, 2004 Partial Decision with Reasons. The Board further notes that the financial impact of the Settlement Proposal is reflected in the "N1, Tab 2" series of exhibits filed with the Settlement Proposal on June 17, 2004. As a result of the Board's findings in this Decision, the revenue requirement for the 2005 Test Year will change relative to that approved by the Board in the Interim Rate Order. Therefore, the Board requires that the Company reflect the changes brought about by this Decision, and the Settlement Proposal, including an updated ROE, in revised financial schedules similar to the "N1, Tab 2" exhibits. These exhibits shall be filed with the Board as soon as possible.

7.1.2 In order to implement new rates as quickly as practicable, the Board hereby directs the Company to file a Draft Final Rate Order with the Board as soon as possible. Given the timing of this Decision, the Board expects that the new rates would be effective January 1, 2005.

8. COST AWARDS

8.1.1 This proceeding involved a number of difficult issues, including several that had accumulated from prior Board proceedings.

8.1.2 The Board received cost award claims from nine claimants, including CEED, CME, CAC, Energy Probe, GEC, IGUA, Pollution Probe, SEC and VECC.

8.1.3 The Board notes that there were no submissions received from the Company with respect to the claims outlined above.

8.1.4 The Board has carefully reviewed all of the submissions including the supporting documentation.

8.1.5 The Board was assisted by the contributions of all of the Parties to this hearing and is generally satisfied with the level of cost awards requested.

8.1.6 The Board orders that 100% of eligible costs of Intervenors as assessed by the Board's Cost Assessment Officer shall be paid by Enbridge Gas Distribution Inc. following the issuance of its Cost Orders.

8.1.7 The Board's costs of, and incidental to, this proceeding shall also be paid by EGDI upon receipt of the Board's invoice.

DATED at Toronto November 1, 2004

Bob Betts
Presiding Member

Paul Sommerville
Member

Pamela Nowina
Member

APPENDIX A

ENBRIDGE GAS DISTRIBUTION INC.

2005 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. RP-2003-0203

ISSUES LIST

NOVEMBER 1, 2004

APPENDIX B

ENBRIDGE GAS DISTRIBUTION INC.

2005 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. RP-2003-0203

SETTLEMENT PROPOSAL

NOVEMBER 1, 2004

APPENDIX C

ENBRIDGE GAS DISTRIBUTION INC.

2005 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. RP-2003-0203

DECISION ON MOTION – MAY 27, 2004

NOVEMBER 1, 2004

APPENDIX D

ENBRIDGE GAS DISTRIBUTION INC.

2005 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. RP-2003-0203

PARTIAL DECISION WITH REASONS – AUGUST 31, 2004

NOVEMBER 1, 2004