500 Consumers Road
North York ON M2J 1P8
P.O. Box 650
Scarborough, ON
M1K 5E3

Shari Lynn Spratt
Supervisor Regulatory Proceedings
phone: (416) 495-6011
fax: (416) 495-6072
Email: shari-lynn.spratt@enbridge.com

May 3, 2011

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Dear Ms Walli:

**Re: Enbridge Gas Distribution Inc. ("the Company")
2010 Earnings Sharing Mechanism and Other Deferral
And Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2011-0008**

Further to the Company's filing of its evidence in the above noted proceeding enclosed please find an updated exhibit. Page 1 of Exhibit A, Tab 3, Schedule 1 has been updated to better facilitate the Company's request of the Ontario Energy Board.

This information is being filed through the Board's RESS system and it will be available on the Company's website @ www.enbridgegas.com/ratecase, as of May 4, 2011.

Yours truly,

SLSpratt

Shari Lynn Spratt
Supervisor Regulatory Proceedings

cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties EB-2010-0146 (via email)

500 Consumers Road
North York ON M2J 1P8
P.O. Box 650
Scarborough, ON
M1K 5E3

Robert Bourke
Manager Regulatory Proceedings
phone: (416) 495-5616
fax: (416) 495-6072
Email: Robert.Bourke@enbridge.com

April 20, 2011

VIA COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("the Company")
2010 Earnings Sharing Mechanism and Other Deferral
And Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2011-0008

Enclosed are two paper copies and an electronic copy on CD, of an Application and supporting evidence by Enbridge Gas Distribution Inc. for an order approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

This information is being filed through the Board's RESS system today.

Enbridge Gas Distribution will provide the Application materials on the Company's website @ www.enbridgegas.com/ratecase as of April 22, 2011.

Yours truly,

Robert Bourke
Manager, Regulatory Proceedings

cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties EB-2010-0146 (via email)

EXHIBIT LIST

A – ADMINISTRATIVE

Exhibit	Tab	Schedule	Contents	Witness(es)
A	1	1	Exhibit List	R. Bourke
	2	1	Application	F. Cass
	3	1	Approvals Requested	K. Culbert R. Small
	4	1	Curriculum Vitae	R. Bourke

B – 2010 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	ESM Calculations	K. Culbert R. Small
		2	ESM Calculations and Required Rate of Return 2010 Historical Year	K. Culbert R. Small
		3	Utility Earnings – Comparison of 2010 Historical Year to 2007 Board Approved	K. Culbert R. Small
		4	Utility Earnings – Reconciliation of 2010 Utility Income to Audited EGDI Consolidated Income	K. Culbert R. Small
		5	Harmonized Sales Tax (HST)	K. Culbert R. Small
		6	Unregulated Storage Review	K. Culbert B. Pilon
		7	Corporate Cost Treatment	K. Culbert R. Lei L. Liauw

EXHIBIT LIST

B – 2010 HISTORICAL YEAR & EARNINGS SHARING RESULTS

EXHIBIT LIST

B – 2010 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	4	1	Operating Cost 2010 Historical Year	K. Culbert R. Small
		2	Operating and Maintenance Expense by Department Ending December 2010	R. Lei A. Patel
	5	1	Required Rate of Return 2010 Historical Year	K. Culbert R. Small
		2	Utility Income 2010 Historical Year	K. Culbert R. Small
		3	Cost of Capital 2010 Historical Year	K. Culbert R. Small

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	1	Balances Requested for Clearance at July 1, 2011	K. Culbert R. Small
		2	Gas Distribution Access Rule Cost Deferral Account explanation	K. Culbert R. Small
		3	Municipal Permit Fees Deferral Account explanation	K. Culbert R. Small
		4	Tax Rate and Rule Change Variance Account explanation	K. Culbert R. Small
		5	Average Use True Up Variance Account explanation	I. Chan

EXHIBIT LIST

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	6	2010 OHCVA	K. Culbert R. Small
	2	1	Clearance of 2010 Deferral and Variance Account Balances	J. Collier A. Kacicnik M. Suarez-Sharma
		2	Derivation of Proposed Unit Rates	J. Collier A. Kacicnik M. Suarez-Sharma

D – REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	Enbridge Gas Distribution Inc. Consolidated Financial Statements December 31, 2010	B. Yuzwa
		2	Enbridge Gas Distribution Inc. Management's Discussion and Analysis – December 31, 2010	B. Yuzwa

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

APPLICATION

1. The Applicant, Enbridge Gas Distribution Inc. ("Enbridge"), is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting and storing natural gas within Ontario.

2. Enbridge hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 36 of the *Ontario Energy Board Act, 1998* (the "Act"), as amended, for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

3. As of January 1, 2011, Enbridge began the fourth year of a five year Incentive Regulation plan ("IR Plan") approved by the Board in EB-2007-0615. The Board-approved Settlement Agreement in EB-2007-0615 (the "Settlement Agreement") provides that Enbridge shall maintain the deferral and variance accounts listed in Appendix B to the Settlement Agreement for the term of the IR Plan. Since that time, there have been several new deferral and variance accounts approved. The Board's Rate Order in EB-2009-0172 dated March 5, 2010 approved the establishment of Enbridge's deferral and variance accounts for 2010. The balances contained in some of those accounts have been approved by the Board, while the balances in other accounts have not yet been reviewed by the Board.

4. The Settlement Agreement provides that clearance of Board-approved balances in Enbridge's deferral and variance accounts will occur in conjunction with each following fiscal year's July 1st Quarterly Rate Adjustment Mechanism ("QRAM") proceeding.

5. The Settlement Agreement specifically addresses the Earnings Sharing Mechanism Deferral Account ("ESMDA") and requires an application by Enbridge to the Board in respect of that account. In this regard, the Settlement Agreement states as follows:

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

6. Enbridge applies to the Board for such final, interim or other Orders as may be necessary or appropriate for the clearance or disposition of the 2010 ESMDA and the other 2010 deferral and variance accounts listed in Appendix A to this Application.

7. Enbridge further applies to the Board pursuant to the provisions of the Act and the Board's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

8. Enbridge requests that a copy of every document filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

Mr. Norm Ryckman
Director, Regulatory Affairs
Enbridge Gas Distribution Inc.

Address for personal service:	500 Consumers Road Willowdale, Ontario M2J 1P8
Mailing address:	P. O. Box 650 Scarborough, Ontario M1K 5E3
Telephone:	416-753-6280
Fax:	416-495-6072
Email:	EGDRegulatoryProceedings@enbridge.com

The Applicant's counsel:

Mr. Fred D. Cass
Aird & Berlis LLP

Address for personal service and mailing address	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	416-865-7742
Fax:	416-863-1515
Email:	fcass@airdberlis.com

DATED April 20, 2011 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: ______________________

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym	Col. 1	Col. 2	Col. 3	Col. 4
			Actual at February 28, 2011		Forecast for clearance at July 1, 2011	
			Principal ($000's)	Interest ($000's)	Principal ($000's)	Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2009 DSMVA	1,165.1	7.2	1,165.1	12.8
2.	Lost Revenue Adjustment Mechanism	2009 LRAM	(45.7)	(0.1)	(45.7)	(0.5)
3.	Shared Savings Mechanism V/A	2009 SSMVA	5,364.2	13.1	5,364.2	39.5
4.	Class Action Suit D/A	2011 CASDA	9,419.1	806.4	4,709.5	463.8 [1]
5.	Deferred Rebate Account	2010 DRA	(2,387.1)	12.4	(2,387.1)	0.8
6.	Gas Distribution Access Rule Costs D/A	2010 GDARCDA	132.7	0.9	2,904.4	- [2]
7.	Ontario Hearing Costs V/A	2010 OHCVA	92.1	0.2	92.1	0.6 [3]
8.	Unbundled Rate Implementation Cost D/A	2010 URICDA	144.1	0.6	144.1	1.4
9.	Open Bill Service D/A	2011 OBSDA	336.2	14.2	87.7	7.9 [4]
10.	Open Bill Access V/A	2011 OBAVA	304.5	7.3	79.4	4.4 [4]
11.	Municipal Permit Fees D/A	2010 MPFDA	901.6	-	306.3	- [2]
12.	Average Use True-Up V/A	2010 AUTUVA	(2,145.2)	(5.3)	(2,145.2)	(15.7) [5]
13.	Tax Rate and Rule Change V/A	2010 TRRCVA	704.0	1.7	516.1	5.3 [6]
14.	Earnings Sharing Mechanism D/A	2010 ESMDA	(18,500.0)	(45.3)	(17,100.0)	(136.1) [7]
15.	IFRS Transition Costs D/A	2010 IFRSTCDA	2,080.6	15.2	2,080.6	25.2
16.	Ex-Franchise Third Party Billing Services D/A	2010 EFTPBSDA	(251.9)	(0.6)	(251.9)	(1.8)
17.	Total non commodity related accounts		(2,685.7)	827.9	(4,480.4)	407.6
	Commodity Related Accounts					
18.	Transactional Services D/A	2010 TSDA	(7,264.5)	(28.7)	(7,264.5)	(64.3)
19.	Unaccounted for Gas V/A	2010 UAFVA	8,729.4	21.4	8,729.4	64.2
20.	Storage and Transportation D/A	2010 S&TDA	(531.8)	(1.7)	(531.8)	(4.5)
21.	Total commodity related accounts		933.1	(9.0)	933.1	(4.6)
22.	Total Deferral and Variance Accounts		(1,752.6)	818.9	(3,547.3)	403.0

Notes:

1. As approved in EB-2007-0731, the CASDA is to be cleared over 5 years (2008 - 2012). The 2008 installment was cleared in July and August 2008, the 2009 installment was cleared in April and May 2010, and the 2010 installment was cleared in January 2011. The Company is now requesting clearance of the 2011, or fourth installment, in this proceeding.

2. The forecast 2010 GDARCDA and 2010 MPFDA amounts for clearance are the result of revenue requirement calculations (found in evidence at Ex.C-1-2 and C-1-3).

3. The OHCVA calculation is found in evidence at Ex.C-1-6.

4. The forecast OBSDA and OBAVA balances are in accordance with the EB-2009-0043 approved Settlement Agreement.

5. The AUTUVA explanation is found in evidence at Ex.C-1-5.

6. The TRRCVA explanation is found in evidence at Ex.C-1-4.

7. The ESMDA explanation is found in evidence at Ex.B-1-1 and B-1-2.

APPROVALS REQUESTED

1. With the filing of this application, the Company is requesting that the Board approve clearance of deferral and variance accounts in conjunction with the following:

a) The Company has filed the balances at February 28, 2011, of Board approved deferral and variance accounts and is requesting approval for their clearance commencing July 1, 2011, (Exhibit C, Tab 1, Schedule 1). Clearance of the balances is proposed as a one time rider adjustment to customers' bills coincident with the Company's July 1, 2011 Quarterly Rate Adjustment Mechanism filing which deals with any required rate adjustments with respect to changes in natural gas prices.

b) Included within the deferral and variance account balances requested for clearance is the 2010 Earnings Sharing Mechanism Deferral Account ("ESMDA") as approved in the Company's EB-2007-0615 proceeding. Evidence in support of the Earnings Sharing calculation and EGD's Fiscal 2010 financial statements are filed in Exhibit B, Tabs 1 through 7 and Exhibit D, Tab 1.

c) The impacts of the clearance of the total deferral and variance account balances by specific rate class are provided in evidence at Exhibit C, Tab 2, Schedules 1 and 2.

d) In order to facilitate the clearance of the deferral and variance accounts through a rate rider within the specific rate classes within the Company's July 1, 2011 QRAM proceeding, a Board Decision is required by approximately June 3, 2011. /u

APPROVALS REQUESTED

1. With the filing of this application, the Company is requesting that the Board approve clearance of deferral and variance accounts in conjunction with the following:

   a) The Company has filed the balances at February 28, 2011, of Board approved deferral and variance accounts and is requesting approval for their clearance commencing July 1, 2011, (Exhibit C, Tab 1, Schedule 1). Clearance of the balances is proposed as a one time rider adjustment to customers' bills coincident with the Company's July 1, 2011 Quarterly Rate Adjustment Mechanism filing which deals with any required rate adjustments with respect to changes in natural gas prices.

   b) Included within the deferral and variance account balances requested for clearance is the 2010 Earnings Sharing Mechanism Deferral Account ("ESMDA") as approved in the Company's EB-2007-0615 proceeding. Evidence in support of the Earnings Sharing calculation and EGD's Fiscal 2010 financial statements are filed in Exhibit B, Tabs 1 through 7 and Exhibit D, Tab 1.

   c) The impacts of the clearance of the total deferral and variance account balances by specific rate class are provided in evidence at Exhibit C, Tab 2, Schedules 1 and 2.

   d) In order to facilitate the clearance of the deferral and variance accounts through a rate rider within the specific rate classes within the Company's July 1, 2011 QRAM proceeding, a Board Decision is required by approximately May 15, 2011.

Witnesses: K. Culbert
R. Small

2. The Board-Approved Settlement Agreement in EB-2007-0615 set out a timeline for the process of the review and clearance of previously approved deferral and variance accounts. Included in the agreement was the requirement of EGD to provide the results of its annual Earnings Sharing calculations for review by the Board and stakeholders as soon as reasonably possible following the completion of EGD's audited year end results approved for public release.

3. The Company proposes an informal stakeholder consultative including intervenors and Board Staff, where it would present, discuss and explain the processes followed in arriving at the results and amounts in the deferral and variance accounts requested for clearance.

4. The Company has filed the ESM calculations in this application at Exhibit B, Tab 1, Schedules 1 and 2. The Company requests that the Board issue a procedural order outlining the timelines of the next steps of the proceeding upon receipt of this application.

Witnesses: K. Culbert
R. Small

CURRICULUM VITAE OF
LINDA AU

Experience:	Enbridge Gas Distribution Inc.
	Capital Budget Manager 2007
	Capital Budget Supervisor 1995
	Revenue and Gas Cost Analyst 1991
	Canada Post Corporation
	Operations Planning and Budget Officer 1990
	Financial Analyst 1988
	Queen Elizabeth Hospital
	Senior Accountant 1986
Education:	Certified General Accountant CGA Ontario 1991
	Bachelor of Business Management Ryerson 1986
Appearances:	(Ontario Energy Board) EB-2010-0042 EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2006-0034 RP-2005-0001

CURRICULUM VITAE OF
ROBERT ALAN BOURKE, CMA

Experience: Enbridge Gas Distribution Inc.

Manager Regulatory Proceedings
2004

Manager Budget and Administration – Operations
2003

Manager Regulatory Accounting
1998

Senior Analyst Regulatory Accounting
1995

Supervisor Revenue and Gas Cost
1992

Centra Gas (Ontario) Inc.

Supervisor, Budget Administration
1992

Thornhill Glass & Mirror Inc.

Controller
1988

The Consumer Gas Company Limited

Manager System Customer Billing
1987

Management Trainee
1986

Supervisor Income and Cash Budget
1982

Asst. Supervisor Income and Cash Budget
1980

Education: Certified Management Accountant (CMA), 1981

Memberships: The Society of Management Accountants Ontario

Appearances:	(Ontario Energy Board)
	EB-2010-0146
	EB-2010-0042
	EB-2009-0172
	EB-2008-0219
	EB-2007-0615
	EB-2006-0034
	EB-2005-0001
	RP-2003-0048
	RP-2002-0133
	RP-2001-0032
	RP-2000-0040
	RP-1999-0001
	EBRO 497
	EBO 179-14/15

CURRICULUM VITAE OF
IRENE CHAN

Experience: Enbridge Gas Distribution

Manager, Margin Accounting, Business Performance and Analytics
2010

Manager, Margin Budgets and Accounting
2007

Manager, Margin Planning and Analysis
2006

Manager, Volumetric Analysis and Budgets
2003

Supervisor, Volumetric Analysis
2001

Senior Analyst, Volumes Knowledge Centre
2000

Economic Analyst, Economic Studies
1998

Queen's University

Instructor, Economics Department
1997

Research/Teaching Assistant, Economics Department
1992-1997

International Monetary Fund

Summer Intern, Research Department
1996

Consultant, Research Department
1994

Bank of Canada

Research Assistant, Research Department
1991

Education:	Certified Management Accountant, The Society of Management Accountants of Canada, 2006
	Ph.D. in Economics Queen's University, 1998
	Master of Arts in Economics Queen's University, 1993
	Bachelor of Arts (Honours) in Economics University of Western Ontario, 1991
Memberships:	Toronto Association for Business & Economics The Society of Management Accountants of Canada
Appearances:	(Ontario Energy Board) EB-2010-0042 EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2007-0615 EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2002-0133

CURRICULUM VITAE OF
JACKIE E. COLLIER

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Design
2003

Manager, Rate Research
2000

Senior Rate Research Analyst
1996

Centra Gas Ontario Inc.

Manager, Rate Design
1995

Supervisor, Cost of Service Studies
1990

Education: Bachelor of Business Management
Ryerson Polytechnical Institute, 1988

Appearances: (Ontario Energy Board)
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
EBRO 489
EBRO 474-B, 483,484
EBRO 474-A
EBRO 474
EBRO 471

(Régie de l'énergie/Régie du gaz naturel)
R-3724-2010
R-3692-2009
R-3665-2008
R-3637-2007
R-3621-2006
R-2587-2005
R-3537-2004
R-3464-2001
R-3446-2000

CURRICULUM VITAE OF
KEVIN CULBERT

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Accounting
Current

Manager, Regulatory Accounting
2003

Senior Analyst, Regulatory Accounting
1998

Analyst, Regulatory Accounting
1991

Assistant Analyst, Regulatory Accounting
1989

Budgets – Capital Clerk, Budget Department
1987

Accounting Trainee, Financial Reporting
1984

Education: CMA (3rd level)
Seneca College 1987-89 (business/accounting)

Appearances: (Ontario Energy Board)
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0104/EB-2008-0408
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203

CURRICULUM VITAE OF
ANTON KACICNIK

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Research & Design
2007

Manager, Cost Allocation
2003

Program Manager, Opportunity Development
1999

Project Supervisor, Technology & Development
1996

Pipeline Inspector, Construction & Maintenance
1993

Education: Bachelor of Applied Science (Civil Engineering)
University of Waterloo, 1996

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0106
EB-2008-0219
EB-2007-0615
EB-2007-0724
EB-2006-0034
EB-2005-0551
EB-2005-0001

(RÉGIE DE L'ÉNERGIE)
R-3724-2010
R-3665-2008
R-3637-2007
R-3621-2006
R-3587-2006
R-3537-2004

CURRICULUM VITAE OF
D. A. KELLY

Experience: Enbridge Gas Distribution Inc.

Manager, Capital Budgets and Accounting
2007

Manager, Operational and Capital Budgets
2005

Manager, Cost Awareness and Analysis
2001

Senior Analyst, Operation and Maintenance
2000

Supervisor, Management Reporting
1997

Supervisor, Corporate Reporting
1992

Analyst, Financial Reporting
1991

Supervisor, Non-Utility Accounting
1989

Financial Statements Accountant
1988

Internal Audit Assistant
1987

Accounting Trainee
1985

Another Company

Corporate Loans, Guaranty Trust
1983

General Accounting, Consumers Glass
1981

Education: Bachelor of Business Management
Ryerson University, 1985

Certified Management Accountant
Society of Management Accountants, 1987

Memberships:	Society of Management Accountants of Ontario
Appearances:	(Ontario Energy Board) EB-2010-0042 EB-2005-0001 RP-2002-0133 RP-2001-0032

CURRICULUM VITAE OF
RAYMOND LEI

Experience:	Enbridge Gas Distribution Inc.
	Manager, Budgets and Business Support 2010
	Manager, Corporate Budgets and Analysis 2007
	Manager, Financial Analysis 2007
	Senior Analyst, Planning and Projects 2005
	Rogers Wireless Inc.
	Senior Analyst, Budgets and Forecast 2001
	Royal LePage Relocation Services Ltd.
	Financial Analyst 2000
	Kodak (China) Limited
	Business Analyst 1995
Education:	Certified General Accountant Certified General Accountants of Ontario, 2005
	Master of Business Administration York University, 2000
	Bachelor of Arts in Commerce and Economics Sichuan University, China
Memberships:	Certified General Accountant, Ontario
Appearances:	(Ontario Energy Board) EB-2010-0146 EB-2010-0042 EB-2009-0172

CURRICULUM VITAE OF
ASHA PATEL

Experience:	Enbridge Gas Distribution Inc.
	Supervisor of O&M Budgets 2010
	Supervisor of External Reporting and Pensions 2008
	Ernst & Young LLP
	Senior Staff Accountant 2008
	Staff Accountant 2006
Education:	Chartered Accountant Institute of Charted Accountants of Ontario, 2008
	Masters of Accounting University of Waterloo, 2006
	Bachelor of Arts, Honours Accountancy Co-op University of Waterloo, 2005
Memberships:	Institute of Chartered Accountants of Ontario

CURRICULUM VITAE OF
BRAD S. PILON

Experience:	Enbridge Gas Distribution Inc.
	Manager, Finance and Administration Gas Storage 2001-Present
	Manager, Administration - Gas Storage 1991-2001
	Tecumseh Storage Analyst 1988-1991
	Manager, Marketing Studies 1986-1988
	Financial Analyst, Exploration 1982-1986
Education:	Executive Education Program for the Natural Gas Industry University of Colorado 1990
	Graduate Studies Masters of Business Administration Program University of Western Ontario 1979-1980
	Bachelor of Arts University of Western Ontario 1979
Memberships:	Ontario Petroleum Institute
Appearances:	(Ontario Energy Board) EB-2005-0001 RP-2003-0203 EBRO 466 EBRO 455

CURRICULUM VITAE OF
RYAN SMALL

Experience:	Enbridge Gas Distribution Inc.
	Senior Analyst, Regulatory Accounting 2006
	Analyst, Regulatory Accounting 2004
	Supervisor, Gas Cost Reporting 2001
	Senior O&M Clerk 2000
	Bank Reconciliation Clerk 1999
	Accounting Trainee 1998
Education:	Certified Management Accountant, The Society of Management Accountants of Ontario, 2003
	Diploma in Accounting, Wilfrid Laurier University, 1997
	Bachelor of Arts in Economics The University of Western Ontario, 1996
Memberships:	The Society of Management Accountants Ontario
Appearances:	(Ontario Energy Board) EB-2011-0008

CURRICULUM VITAE OF
MARGARITA SUAREZ-SHARMA

Experience: Enbridge Gas Distribution Inc.

Manager, Cost Allocation
2008

Manager, DSM Reporting & Analysis
2005

Analyst, Rate Design
2004

Senior Analyst, DSM Planning and Evaluation
2002

Senior Economic Analyst, Economic & Financial Studies
1998

Margaret Chase Smith Center for Public Policy

Research Assistant
1995

Education: Master of Arts in Economics
University of Maine, 1995

Bachelor of Arts in Economics
University of Maine, 1993

Appearances: (ONTARIO ENERGY BOARD)
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106

(RÉGIE DE L'ÉNERGIE)
R-3724-2010
R-3692-2009
R-3665-2008

CURRICULUM VITAE OF
MARC N. WEIL

Experience: Enbridge Gas Distribution Inc.

Director, Human Resources & Facilities
2010

Director, Information Technology
2006

Manager, Application Support
2004

Enbridge Inc.

Supervisor, Corporate IT Operations
2001

Enbridge Pipelines Inc.

Senior Systems Analyst
2000

Systems Analyst III
2000

Systems Analyst II
1998

Systems Analyst I
1997

Education: Management Essentials – Mini MBA – Executive Education
University of Calgary, 2003

Bachelor of Commerce (Management Information Systems)
University of Alberta, 1997

Business Administration Diploma (Management)
Northern Alberta Institute of Technology, 1994

Appearances: (Ontario Energy Board)
EB-2006-0034

CURRICULUM VITAE OF
BARRY C. YUZWA

Experience: Enbridge Gas Distribution Inc.

Director, Finance & Control
2010

Enbridge Inc.

Senior Director, Chief Audit Executive
Audit Services & Internal Controls
2007

Director, Audit Services
1999

Safeway Inc./Canada Safeway Limited

Manager, Corporate Audit Services
1991

Deloitte & Touche

Audit Manager
1987

Education: Certified Internal Auditor
Institute of Internal Auditors, 2003

Chartered Accountant
Canadian Institute of Chartered Accountants, 1986

Bachelor of Commerce-Accounting
University of Calgary, 1983

Memberships: Canadian Institute of Chartered Accountants
Institute of Chartered Accountants of Alberta
Institute of Chartered Accountants of Ontario
Institute of Internal Auditors
Financial Executives International, Canada
Corporate Executive Board, Audit Directors and Risk Management Advisory Council
University of Calgary, Haskayne School of Business, Mentorship Program
Enbridge Inc. Mentorship Program

2010 EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. The 2010 Earnings Sharing amount requested for approval and clearance in this application is $17.1 million.

   Enbridge Gas Distribution Inc's. Fiscal 2010 year end audited financial statement showed an estimated utility related earnings sharing accrual of $18.5 million. In order to meet year end timing obligations, estimates for elements impacting the accrual are sometimes required in lieu of complete or detailed analyses. Following the year end close process, however, completion of detailed analyses is performed for elements where estimates were used in order to ensure the earnings sharing accrual was accurate. If required and appropriate, an adjustment is made to the earnings sharing results, which is reflected in the following year financial statements.

2. For Fiscal 2010, the completion of true-up of estimates in relation to an HST impact analysis and completion of an analysis of the required treatment of corporate cost allocations in utility earnings sharing results was performed, with the result being an adjusted 2010 earnings sharing amount of $17.1 million.

3. This same process has been followed to confirm the earnings sharing amount each year, as evidenced in Fiscal 2009 where the year-end financial statement earnings sharing accrual was subsequently increased by $0.6 million in the EB-2010-0042 application.

Witnesses: K. Culbert
R. Small

4. An explanation of the required HST analyses and corporate cost treatment analysis which followed the year end close process are located at Exhibit B, Tab 1, Schedules 5 and 7 respectively and are briefly summarized in Appendix A of this schedule.

5. The amounts for utility purposes for each of the cost elements of rate base, utility income and taxes, and the capital structure components, which were used in the calculation of the earnings sharing amount, are summarized in Exhibit B, Tab 1, Schedule 2.

6. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2007-0615 Board Approved Settlement Agreement (Exhibit N1, Tab 1, Schedule 1, p. 27):
   - if in any calendar year, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than 100 basis points over the amount calculated annually by the application of the Board's ROE Formula in any year of the IR Plan, then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge and its ratepayers;
   - for the purposes of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings; and
   - all revenues that would otherwise be included in revenue in a cost of service application shall be included in revenues in the calculation of the earnings calculation and only those expenses (whether operating or capital) that would be

otherwise allowable as deductions from earnings in a cost of service application, shall be included in the earnings calculation.

7. In the EB-2007-0615 Settlement Agreement the Parties acknowledged that the following shareholder incentives and other amounts are outside the ambit of the ESM:
   - amounts in respect of the application of the Shared Savings Mechanism (“SSM”) and the LRAM (“Lost Revenue Adjustment Mechanism”);
   - amounts related to storage and transportation related deferral accounts; and
   - the Company’s 50% share of the tax amount calculated in association with expected tax rate and rule changes as per the settlement (Exhibit N1, Tab 1, Schedule 1, p. 23).

8. As shown in the summary of return on equity and earnings sharing determination at Exhibit B, Tab 1, Schedule 2, the Company has calculated earnings for sharing purposes in two ways for confirmation purposes.

9. In part A) of the summary, a return on rate base method is shown, while in part B), a return on equity from a deemed equity embedded within rate base perspective is shown. Column 2 in the exhibit provides references indicating where additional evidence in support of the determination of the amounts in the summary can be found. Column 3 contains results shown in units of millions of dollars or percentages.

Witnesses: K. Culbert
R. Small

Part A)

10. The level of utility income, $306.0 million (Line 19) divided by the level of utility rate base, $3,837.7 million (Line 24) generates a utility return on rate base of 7.974% (Line 25).

11. When compared to the Company's required rate of return of 7.360% (Line 26), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.614% (Line 27) on total rate base.

12. As shown in Lines 28 through 30, the sufficiency of 0.614% multiplied by the rate base of $3,837.7 million, produces a net over earnings or sufficiency of $23.56 million which from a pre-tax perspective, ($23.56 million divided by the reciprocal, 69.0%, of the corporate tax rate) shows a $34.15 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Part B) (Confirming the Calculated Earnings Sharing)

13. Net utility income applicable to common equity is first determined.

14. The $377.2 million (Line 33) of utility income before income tax, less utility taxes of $71.2 million (Line 38), produces the $306.0 million of utility income used in part A) above (at Line 19).

15. In order to determine utility net income applicable to a deemed common equity percentage in rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $306.0 million utility income.

Witnesses: K. Culbert
R. Small

16. These reductions are shown at Lines 34 to 36 which along with the utility income tax reduction already mentioned and shown at Line 38, results in a net income applicable to common equity of $153.0 million, shown at Line 39.

17. The $153.0 million, divided by the deemed common equity level of $1,381.6 million (Line 40, calculated as 36% of the $3,837.7 million rate base) produces a return on equity of 11.075% (Line 42). When comparing the 11.075% achieved return on equity to the threshold ROE percentage of 9.37% (Line 41), which is the Board approved formula return on equity for 2010 of 8.37% plus the approved 100 basis point dead band, there is a sufficiency in ROE of 1.71% (Line 43).

18. The 1.71% multiplied by the common equity level of $1,381.6 million (Line 40) produces a net over earnings or sufficiency of $23.56 million which from a pre-tax perspective, ($23.56 million divided by the reciprocal, 69.0%, of the corporate tax rate) shows a $34.15 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

<u>ESM Elements and Adjustments</u>

19. The calculation of utility earnings and any sharing requirement starts with financial results contained in the EGD corporate trial balance.

20. From there, in order to calculate the Ontario utility rate base, income and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the Board and the standards associated

with cost of service rate related accounting processes. Examples are:

- determination of rate base amounts using the average of monthly averages value concept,
- elimination of corporate interest expense due to the treatment of interest expense as embedded in the capital structure balanced to rate base, and
- elimination of corporate income taxes due to the determination of income taxes specific to utility results,

21. In addition, EGD has made the appropriate adjustments in relation to non standard rate regulated items which the Board has either decided in the past, were agreed to in the EB-2007-0615 approved settlement, or are required in order to determine an appropriate utility return on equity in the Incentive Regulation versus Cost of Service construct. Examples are:
    - rate base disallowance from EBRO 473 and 479 Decisions (Mississauga Southern Link project amounts),
    - rate base disallowance from RP-2002-0133 (shared assets),
    - exclusion of non-utility or unregulated activities,
    - elimination of EGD share of SSM;
    - elimination of EGD share of transactional services, and
    - elimination of EGD share of tax rate and rule changes.

22. As shown in the Column 2 references in the summary exhibit, supporting rate base information is found in Exhibit B, Tab 2, supporting revenue, volumes, customers and cost information is found in Exhibit B, Tabs 3 & 4, and supporting capital structure, required rate of return, utility income, and costs of capital information is found in Exhibit B, Tab 5.

Witnesses: K. Culbert
R. Small

APPENDIX A

1. An analysis of the financial impacts of the implementation of HST effective July 1, 2010 is included in evidence at Exhibit C, Tab 1, Schedule 4. The analysis included a review of the impact which the change specifically has in relation to the former GST, and now HST, working cash component in utility rate base for 2010-2012. An assumption in the analysis and estimate used at the time of year end was that as of July 1, 2010, HST (at 13%) versus GST (at 5%), would be applicable to all gas purchases. Completion of the analysis identified that HST would not in fact apply to gas purchase transactions completed outside of Ontario. The result was that the original HST analysis had identified that a working cash rate base increment of $1 million would occur in 2010 whereas the recently completed analysis indicates an HST working cash rate base reduction of $3.2 million. The result is that the year-end credit amount of $0.3 million accrued into the Tax Rate and Rule Change Variance Account ("TRRCVA"), which had a corresponding reduction to pre-tax revenue, now becomes $0.5 million. The increase of $0.2 million in the credit amount to the TRRCVA requires and produces an approximate reduction to the 2010 earnings sharing amount of $0.2 million amount from the originally accrued amount of $18.5 to $18.3 million.

2. As explained in evidence at Exhibit B, Tab 1, Schedule 7, EGD completed its analysis of the corporate cost treatment in utility earnings. Within the year-end process, the difference between amounts derived under a Corporate Cost Allocation Methodology ("CAM") and the Regulated Corporate Cost Allocation Methodology ("RCAM") approved by the Board and updated annually, is removed from costs allowed in utility earnings and earnings sharing calculations. Within

the process, data extractions produced an estimated level of CAM of approximately $39.1 million as being resident in fiscal year-end financial results. The use of that estimate resulted in year-end utility earnings calculations containing an elimination of $14.8 million from utility O&M, representing the difference between the estimated CAM amount of $39.1 million and the updated RCAM amount of $24.3 million. The completion of the corporate cost treatment analysis, where the actual CAM level resident in year-end results was found to be $36.7 million, revealed that the elimination from utility O&M in comparison to the RCAM amount of $24.3 million should be $12.4 million. Incorporating the findings of the analysis results in a decrease to the removal of utility O&M of $2.4 million and an approximate reduction to after tax utility earnings of $1.7 million with a corresponding reduction to the pre-tax earnings sharing accrual of approximately $1.2 million. The resulting original earnings sharing accrual of $18.5 therefore becomes $17.1 million after the effects of the $0.2 million TRRCVA related adjustment and the $1.2 million adjustment explained above.

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2010

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual Normalized ($millions) & (%'s)
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
2.	Gas Sales	(Ex.B,T5,S2,P1,Col.1,line 1)	1,988.0
3.	Transportation Revenue	(Ex.B,T5,S2,P1,Col.1,line 2)	460.1
4.	Less Cost of Gas	(Ex.B,T5,S2,P1,Col.1,line 8)	1,450.7
5.	Gas Distribution Margin		997.4
6.	Transmission, Compr. and Storage Revenue	(Ex.B,T5,S2,P1,Col.1,line 3)	1.4
7.	Other Revenue	(Ex.B,T5,S2,P1,Col.1,line 4)	40.5
8.	Other Income	(Ex.B,T5,S2,P1,Col.1,line 6)	13.3
9.	Total - TC&S, Oth. Rev. & Inc.		55.2
10.	Operations, Maintenance & Administration	(Ex.B,T5,S2,P1,Col.1,line 9)	346.7
11.	Depreciation & amortization	(Ex.B,T5,S2,P1,Col.1,line 10)	266.9
12.	Fixed financing costs	(Ex.B,T5,S2,P1,Col.1,line 11)	4.8
13.	Debt redemption premium amortization	(Ex.B,T5,S2,P1,Col.1,line 12)	0.3
14.	Company share of IR agreement tax savings	(Ex.B,T5,S2,P1,Col.1,line 13)	16.0
15.	Municipal & capital taxes	(Ex.B,T5,S2,P1,Col.1,line 14)	40.7
16.	Total O&M, Depr., & other		675.4
17.	Utility Income before Income Tax	(line 5 + line 9 - line 16)	377.2
18.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	71.2
19.	**Utility Income**		**306.0**
20.	Gross plant	(Ex.B,T2,S1,P1,Col.1,line 1)	5,807.2
21.	Accumulated depreciation	(Ex.B,T2,S1,P1,Col.1,line 2)	(2,235.7)
22.	Net plant		3,571.5
23.	Working capital	(Ex.B,T2,S1,P1,Col.1,line 12)	266.2
24.	**Utility Rate Base**		**3,837.7**
25.	Indicated Return on Rate Base %	(line 19 / line 24)	7.974%
26.	Less: Required Rate of Return %	(Ex.B,T5,S1,P1,Col.4,line 6)	7.360%
27.	(Deficiency) / Sufficiency %		0.614%
28.	Net Earnings (Deficiency) / Sufficiency	(line 27 x line 24)	23.56
29.	Provision for Income Taxes		10.59
30.	Gross Earnings (Deficiency) / Sufficiency	(line 28 divide by 69.0%)	34.15
31.	**50% Earnings sharing to ratepayers**	(line 30 x 50%)	**17.08**
32.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
33.	Utility Income before Income Tax	(Ex.B,T5,S2,P1,Col.1,line 18)	377.2
34.	Less: Long Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 1)	148.3
35.	Less: Short Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 2)	2.6
36.	Less: Cost of Preferred Capital	(Ex.B,T5,S1,P1,Col.5,line 4)	2.1
37.	Net Income before Income Taxes		224.2
38.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	71.2
39.	Net Income Applicable to Common Equity	(line 37 - line 38)	153.0
40.	Common Equity	(Ex.B,T5,S1,P1,Col.1,line 5)	1,381.6
41.	Approved ROE %	(EB-2007-0615 for Earnings Sharing 8.37% + 100 bp)	9.370%
42.	Achieved Rate of Return on Equity %	(line 39 divide by line 40)	11.075%
43.	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.71%
44.	Net Earnings (Deficiency) / Sufficiency	(line40 x line 43)	23.56
45.	Provision for Income Taxes		10.60
46.	Gross Earnings (Deficiency) / Sufficiency	(line 44 divide by 69.0%)	34.15
47.	**50% Earnings sharing to ratepayers**	(line 46 x 50%)	**17.08**

Witnesses: K. Culbert
R. Small

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUINTS
FOR FISCAL YEAR 2010

Line No.		Col. 1 2010 Actual Normalized $Millions	Col. 2 2007 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	1,988.0	2,369.1		
2.	Transportation revenue	460.1	748.8		
3.	Transmission, compression & storage	1.4	1.9		
4.	Gas costs	1,450.7	2,174.6		
5.	Distribution margin	998.8	945.2	53.6	a)
6.	Other revenue	40.5	34.3	6.2	b)
7.	Other income	13.3	0.2	13.1	c)
8.	O&M	346.7	326.2	(20.5)	d)
9.	Depreciation expense	266.9	227.3	(39.6)	e)
10.	Other expense	61.8	56.4	(5.4)	f)
11.	Income taxes	71.2	85.8	14.6	g)
12.	Utility Income	306.0	284.0	22.0	
13.	LTD & STD costs	150.9	165.8	14.9	h)
14.	Preference share costs	2.1	5.0	2.9	h)
15.	Return on Equity @ 9.37%[1] in 2010, 8.39% in 2007	129.5	113.2	(16.3)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	23.6	(0.0)	23.6	
17.	Provision for taxes on Earnings Over / (Under)	10.6	(0.0)	10.6	
18.	Gross Earnings Over / (Under)	34.2	(0.0)	34.2	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,381.6			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	153.0			
21.	EGD normalized Return on Equity	11.08%			

[1] 8.37% as per Board Approved formula using October 2009 consensus forecast, plus 100 basis points as per 2008 incentive regulation Board Approved agreement.

Witnesses: K. Culbert
R. Small

2010 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

1. The following are explanations of the Utility Normalized Earnings results as compared to the 2007 Board Approved amounts. The reference letters are in relation to those identified on page 1 of this schedule.

   a) The distribution margin change of $53.6 million is mainly the result of the change in revenue derived from EGD's IR framework and formula where forecast cumulative 2010 IR formula revenue was an increase of $64.9 million from the base year DRR amount (beginning amount in 2008 was $753.2, ending amount in 2010 was $818.1, EB-2009-0172 Rate Order Appendix A), increases in DSM and Customer Care related Y-Factors versus 2007 Board Approved levels and, partially offsetting lower required recoveries of carrying costs of gas in storage and working cash elements due to lower average gas commodity pricing within the 2010 QRAM's versus pricing embedded in 2007 approved rates. This results in a positive impact on earnings.

   b) The other revenue change of $6.2 million is due to increased late payment penalty revenue of $5.1 million, an increase in service charges of $1.7 million and a decrease in other revenue of $(0.6) million. This results in a positive impact on earnings.

   c) The other income change of $13.1 million is mainly due to revenue from the management of fee for service, external 3rd party energy efficiency initiatives. This results in a positive impact on earnings.

Witnesses: K. Culbert
R. Small

d) Utility O&M is $20.5 million above that of the 2007 approved level embedded in base rates used in the incentive regulation escalation formula. The details of utility O&M are provided at Exhibit B, Tab 4, Schedule 2. This results in a reduction in earnings.

e) The increase in depreciation expense of $39.6 million is due to higher levels of property, plant, and equipment associated with customer growth and system improvement activities in each of 2008, 2009, and 2010, and the implementation of the new CIS system in 2009. The impact of increases in customer growth and system improvements in P.P.& E. in 2008 and 2009 has a full year depreciation increase impact in 2010, while the increases relative to 2010 have a part year depreciation increase impact. The depreciation expense increase results in a reduction to earnings.

f) Other expense increases of $5.4 million are the result of, an increase in recognition of EGD's $16.0 million share of the IR agreement tax savings impact within 2009 results, an increase in fixed financing costs of $3.8 million, a decrease from the elimination of the notional utility account amounts versus the 2007 approved level of $9.2 million, and decreases in municipal and capital tax of approximately $5.2 million mostly the result of decreased capital tax rates as recognized in the IR tax savings agreement. The net result is a reduction in earnings.

g) Income tax changes are the result of the impact on taxable income of the above noted items along with differences in tax add back and tax deductible allowances per the Canada Revenue Agency and a change in the overall corporate income tax rate. This results in a positive impact on earnings.

Witnesses: K. Culbert
R. Small

h) The interest cost of utility long, medium and short term debt and preference share costs changed by $17.8 million relative to 2007 approved levels as a result of lower overall average cost rates. This results in a positive impact on earnings.

Witnesses: K. Culbert
R. Small

RECONCILIATION OF AUDITED EGDI
CONSOLIDATED INCOME TO UTILITY INCOME
2010 HISTORICAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line no.		Audited Consolidated Income ($millions)	Utility Income ($millions)	Difference ($millions)	Reference
1.	Gas commodity and distribution revenue	1,977.1	1,988.0	10.9	a)
2.	Transportation of gas for customers	389.5	460.1	70.6	b)
3.		2,366.6	2,448.1	81.5	
4.	Gas commodity and distribution costs	1,371.9	1,450.7	78.8	c)
5.	Gas distribution margin	994.7	997.4	2.7	
6.	Other revenue	108.2	55.2	(53.0)	d)
7.		1,102.9	1,052.6	(50.3)	
	Expenses				
8.	Operation and maintenance	393.3	346.7	(46.6)	e)
9.	Earnings sharing	18.9	-	(18.9)	f)
10.	Depreciation	269.9	266.9	(3.0)	g)
11.	Municipal and other taxes	44.0	40.7	(3.3)	h)
12.	Company share of IR agreement tax savings	-	16.0	16.0	i)
13.		726.1	670.3	(55.8)	
14.	Income before undernoted items	376.8	382.3	5.5	
15.	Financing income	62.7	-	(62.7)	j)
16.	Interest and financing expenses	(185.7)	(5.1)	180.6	k)
17.	Income before income taxes	253.8	377.2	123.4	
18.	Income taxes	60.5	71.2	10.7	l)
19.	Net Income	193.3	306.0	112.7	

Witnesses: K. Culbert
R. Small

RECONCILIATION OF 2010
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
a)	1,977.1	**Consolidated gas commodity and distribution revenue**
	(36.4)	Amounts related to St. Lawrence Gas
	45.8	Normalization adjustment
	1.7	Gazifere T-service regrouped to gas commodity and distribution revenue
	(0.2)	Adjustment relating to the updated tax saving sharing agreement
	1,988.0	**Utility gas commodity and distribution revenue**
b)	389.5	**Consolidated transportation of gas for customers**
	(5.4)	Amounts related to St. Lawrence Gas
	9.6	Normalization adjustment
	(1.7)	Gazifere T-service regrouped to gas commodity and distribution revenue
	68.1	Western T-Service Credits regrouped to gas costs
	460.1	**Utility transportation of gas for customers**
c)	1,371.9	**Consolidated gas commodity and distribution costs**
	(27.2)	Elimination of amounts related to St. Lawrence Gas and unregulated storage
	38.0	Normalization adjustment
	68.1	Western T-Service Credits regrouped to gas costs
	(0.1)	Rounding
	1,450.7	**Utility gas commodity and distribution costs**

Witnesses: K. Culbert
R. Small

RECONCILIATION OF 2010
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
d)	108.2	**Consolidated other revenue**
	(15.0)	Amounts related to St. Lawrence Gas, unregulated storage, and oil and gas
	(12.8)	Open Bill O&M expenses regrouped against program revenues
	(6.1)	ABC administration and bad debt costs regrouped against program revenues from O&M
	(0.1)	ABC interest charges regrouped against program revenues
	2.8	Allowable interest during construction regrouped to revenues from interest and financing expenses
	0.3	NGV program revenue imputation
	(3.3)	Elimination of transactional services revenue above base amount included in rates
	0.2	Elimination of the shareholder portion of the OBSDA and OBAVA write-off
	(0.3)	Elimination of the shareholder portion of net ex-franchise Open Bill revenues
	(1.9)	Elimination of Open Bill revenues to reflect the shareholder incentive
	(1.4)	Elimination of affiliate and 3rd party asset use revenue considered non-utility
	(6.7)	Elimination of net ABC revenue considered non-utility
	(0.4)	Elimination of interest income from investments not included in rate base
	(2.8)	Elimination of allowable interest during construction
	(5.4)	Elimination of shareholders' incentive income recorded as a result of calculating the SSMVA amount
	(0.1)	Rounding
	55.2	**Utility other revenue**
e)	393.3	**Consolidated operation and maintenance**
	(11.8)	Amounts related to St. Lawrence Gas, unregulated storage, and oil and gas
	(12.8)	Open Bill expenses regrouped against program revenues
	(6.1)	ABC administration and bad debt costs regrouped against program revenues and eliminated
	0.5	Interest on security deposits added to utility O&M
	(1.6)	Elimination of donations
	(1.8)	Elimination of non-utility costs of supporting the ABC program
	(12.4)	Elimination of Corporate Cost Allocations above RCAM amount
	(0.5)	To remove the expensing of the 2009 OHCVA from utility O&M
	(0.1)	Rounding
	346.7	**Utility operation and maintenance**
f)	18.9	**Consolidated earnings sharing**
	(18.9)	Elimination of earnings sharing amounts within year end financials from utility income calculation
	-	**Utility earnings sharing**
g)	269.9	**Consolidated depreciation**
	(2.7)	Amounts related to St. Lawrence Gas, unregulated storage, and oil and gas
	(0.2)	Elimination of depreciation on disallowed Mississauga Southern Link
	(0.1)	Elimination of depreciation related to shared assets
	266.9	**Utility depreciation**

Witnesses: K. Culbert
R. Small

RECONCILIATION OF 2010
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
h)	44.0	**Consolidated municipal and other taxes**
	(1.6)	Amounts related to St. Lawrence Gas, unregulated storage, and oil and gas
	(0.2)	Elimination of municipal taxes related to shared assets
	(1.6)	Adjustment to convert capital taxes to a utility "stand-alone" basis
	0.1	Rounding
	40.7	**Utility municipal and other taxes**
i)	-	**Consolidated IR agreement tax savings**
	16.0	Recognition of the Company's share of IR agreement tax savings, as determined in EB-2007-0615, and updated in EB-2009-0172, EB-2010-0146, and this proceeding
	16.0	**Utility IR agreement tax savings**
j)	62.7	**Consolidated financing income**
	(62.7)	Eliminate non-utility dividend income from the Board Approved financing transaction
	-	**Utility financing income**
k)	185.7	**Consolidated interest and financing expenses**
	(2.6)	Amounts related to St. Lawrence Gas, unregulated storage, and oil and gas
	(26.8)	Eliminate non-utility interest expense from the Board Approved financing transaction
	2.8	Allowable interest during construction regrouped to revenues and eliminated
	(0.1)	ABC interest charges regrouped against program revenues and eliminated
	(153.9)	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure
	5.1	**Utility interest and financing expenses**
l)	60.5	**Consolidated income taxes**
	(3.8)	Amounts related to St. Lawrence Gas, unregulated storage, and oil and gas
	(56.7)	Elimination of corporate income taxes
	71.2	Addition of income taxes calculated on a utility "stand-alone" basis
	71.2	**Utility income taxes**

Witnesses: K. Culbert
R. Small

HARMONIZED SALES TAX ("HST")
RATES/EARNINGS IMPACT ANALYSIS

1. The following analysis has been prepared and filed in accordance with EGD's 2010 Test Year, EB-2009-0172, Board Approved Settlement Proposal.

Requirement of Analysis

2. Exhibit N1, Tab 1, Schedule 1, page 14 of the Settlement Proposal, identified that EGD would perform an analysis of the impacts of the transition to the harmonized sales tax ("HST"), which became effective in July 2010, and would bring forward the results for review in 2011 as recorded in the 2010 Tax Rate and Rule Change Variance Account ("TRRCVA").

3. The agreement to perform such analysis arose from questions about whether the change to HST, in relation to PST amounts specific to and being recovered within the 2007 Test Year rates and continuing to be recovered in ongoing rates in EGD's 2008-2012 Incentive Regulation ("IR") term, could be creating an earnings impact in 2010, 2011, and 2012. As per the tax rate and rule change sharing agreement included in EGD's IR model, any earnings impact determined to be resulting from tax rate or rule changes relative to base 2007 Board Approved levels is to be shared equally between EGD and ratepayers. Any amounts to be credited or debited for ratepayers are to be recorded in the TRRCVA for future return or recovery.

Background to Analysis Performed

4. In order to determine what, if any, approximate earnings impact is occurring as a result of the PST to HST change, a revenue requirement calculation / analysis had to be performed. To begin, the analysis had to consider the effect of the change on

amounts being capitalized into rate base, levels of operating cost / depreciation and income taxes within utility income and impacts within cost of capital. To be meaningful, the end result of the analysis had to calculate how all of these effects were impacting the total actual revenue requirements occurring in 2010, 2011 and 2012 utility financial results in comparison to 2007 Board Approved levels as per the intent of the tax savings sharing agreement and TRRCVA.

5. For example, PST amounts assumed to be embedded in the 2007 approved revenue requirement, in association with certain capital expenditures, would have been included in an asset category contained in rate base. The relevant factor is the total revenue requirement embedded in rates, inclusive of the cost of capital, depreciation, and income taxes on the PST amount capitalized, not simply the PST amount itself. Similarly (as of July 1, 2010) for a capital expenditure which previously attracted PST and now attracts HST (for which EGD can claim an HST credit), or which now attracts HST and did not previously attract PST (for which EGD cannot claim an HST credit), neither the HST amount nor any associated HST credit is the relevant factor. The relevant factor is whether there is a change in earnings or actual revenue requirement relating to HST treatment as compared to the forecast revenue requirement assumed to be incorporated within ongoing rates relating to PST treatment. In summary, the accumulation and comparison of specific PST or HST amounts incurred as a result of capital spending is not relevant within any analysis until converted into an estimated revenue requirement and related earnings impact.

6. The analysis of any earnings impact of former PST amounts incurred in operating and maintenance costs, now incurred as HST with associated credits or new HST related items with no credit available, is more straightforward. Generally, each

dollar increase or decrease is representative of an equivalent change in revenue requirement or gross earnings.

7. Another item, which the Company agreed to review, is the impact of the implementation of HST in relation to the existing GST element in the working cash component of rate base, which is explained later in this evidence.

Scope of the Analysis

8. In planning the analysis, other considerations were identified. One consideration was that the approved tax savings sharing agreement utilized forecast amounts which were known to be resident in the 2007 approved revenue requirement in determining the impacts to be equally shared. In order to meet that scope of the tax savings sharing agreement, it was determined that the analysis would have to attempt to estimate how the revenue requirement for the 2007 Test Year, when considering the impact of that years forecast or budgeted PST related costs, might have changed on an annual basis for 2010, 2011 and 2012 under a cost of service type calculation when considering the new HST rules.

9. Therefore, in order to estimate how the 2007 Test Year revenue requirement was impacted by PST forecast related amounts, PST amounts would have to have been separately identifiable in the budget. However, EGD's budget for the 2007 Test Year (or any other year) did not contain segregated PST related amounts, and such a calculation cannot be performed. As a result, another means and or data set had to be used for estimating the potential impacts to the 2007 approved revenue requirement and related future earnings impacts.

10. From there, it was decided that an annual set of PST costs actually incurred might be a reasonable proxy for use in estimating the impact of 2007 related PST costs

embedded within the 2007 approved revenue requirement. At the time of the analysis, 2009 actual PST costs were the most recent annual data set available and it was decided that they could represent a reasonable proxy for use in the analysis. The philosophy was that other years' actual PST cost data could also be viewed as being a reasonable proxy for use in the analysis, however, the PST data from 2009 would not necessarily be materially different from other years and as a side benefit, might also be additionally indicative of the impacts occurring in 2010 and beyond.

Data Used in the Analysis

11. In assessing the manner in which HST would be applied, the Company identified three categories of expenditures for the comparison of HST applicability versus former PST applicability. A first category, relevant to the analysis, is expenditures where HST is, and the former PST was, applicable but for which EGD now can claim an HST credit (PST had no credits). A second category, which is also relevant to the analysis, is expenditures where HST is now applicable but PST was not previously applicable, for which EGD cannot claim an HST credit. A third category, which is irrelevant to the analysis, because the cost to EGD did not change, is expenditures where HST is, and the former PST was, applicable and for which no HST credit is available.

12. As a next step, a data extraction from 2009 actual records was performed that accumulated PST amounts incurred on actual expenditures. While PST amounts have never been required to be tracked separately within EGD's records, to the extent possible the data extraction was able to link the PST amounts to the underlying capital or operating and maintenance expenditure. Additionally, where the assessment of HST applicability identified types of expenditures as outlined in the third category described above, the Company performed an extraction of the

level of costs incurred within 2009 and estimated the additional HST which would have been incurred. Considerable efforts were undertaken in the process of gathering the data and interpreting and assessing what the HST versus PST treatments would mean to the data.

13. The resulting data, which was extracted from 2009 actual records and relative to the first category described above, showed that $5.9 million of PST was incurred, primarily with capital spending and property, plant and equipment, and that $1.3 million of PST was incurred in association with operating and maintenance spending. The data was used to estimate the total PST revenue requirement impacts contained in the 2007 approved revenue requirement as compared to what the impact would have been in 2010 through 2012 (using HST, as applicable). Shown in the attached Appendix A, are the estimated impacts occurring in each of the revenue requirement components of capital structure, rate base, utility income, and income taxes in each of 2010 through 2012.

14. The second category listed above is required in relation to certain energy related costs that PST did not formerly apply to, but which HST has applied to since July 2010, with no corresponding HST credit available. Using 2009 data as a proxy, the amount of HST which would be incurred relative to amounts in rates for which no HST credit is available, would be approximately $0.1 million of operating costs. This data was also used in the estimated impacts in the revenue requirement elements shown in Appendix A.

Witnesses: K. Culbert
R. Small

Explanation of Derivation of Revenue Requirement Impacts

15. The analysis was prepared using cost of service revenue requirement principles and utilized the 2007 Board Approved, capital structure for cost of capital requirements, Board Approved depreciation rates, and current and forecast tax rates as included in the tax rate and rule change sharing agreement.

16. For example, in the attached rate base schedule shown at Appendix A, page 2, the impacts shown in the property, plant, and equipment and prepaid expense categories represent the assumed difference that would be occurring in rate base where the proxy $5.9 million (see para. 13) change in PST versus HST is no longer being capitalized in fiscal years 2010-2012. The estimated cumulative annual rate base impacts, calculated on an average of monthly averages basis, were determined using the 2009 proxy PST amounts extracted by asset category, assuming they would have been capitalized evenly throughout the year. For 2010, 50% of proxy amounts were used and considered effective from July 1st and onwards due to the HST's implementation on July 1, 2010. Depreciation impacts were determined using approved depreciation rates and corresponding accumulated depreciation was calculated on an average of monthly average basis as well.

17. Additionally in rate base, the GST component of the working cash allowance requirement is impacted as a result of now incurring and collecting HST as opposed to GST. The annual GST related working cash requirement of $1.8M included in the July 1, 2010, EB-2010-0186 approved rates was used as a benchmark in the analysis due to the HST change occurring on that date. The analysis only looked at the impact of how the newly imposed HST rates at 13% (versus GST at 5%), would affect the annual working cash requirement. In applying the new HST rate to

elements which underpinned the working cash calculation, the GST/HST related requirement decreases by $6.4 million, to a $4.5 million credit. The decrease in requirement is mainly due to an increased cash flow benefit in the GST/HST working cash element arising from HST being applicable entirely to revenue while not applicable to all costs, an example is the GST but not total HST rate that is applicable to gas purchase transactions in western Canada. As the $6.4 million decrease is an annual rate base impact, the analysis assumes it is only half effective for 2010 or $3.2 million (Appendix A, p. 2, Col. 1, Line 11). The $6.4 million decrease is effective on a full year basis for 2011 and 2012.

18. The utility income and income tax calculations, in the attached Appendix A, pages 3 and 4, were determined using cost of service principles.

Revenue Requirement Analysis Results

19. Shown in the attached Appendix A, pages 1 through 5, are the estimated impacts of the July 1, 2010, change in the Company's 2010 through 2012 Utility revenue requirements and related earnings calculations.

20. Page 1 of Appendix A, shows a summary of the estimated impacts to utility income, rate base and related sufficiencies in return on equity and earnings. The estimated beneficial impact or sufficiency in pre-tax earnings, shown at page 1, Line 12, for each of 2010, 2011 and 2012 is $908 thousand, $2,379 thousand, and $3,041 thousand respectively. As indicated previously, the Tax Rate and Rule Change sharing agreement specifies that these amounts are to be shared equally between EGD and its ratepayers. The sharing impacts have been incorporated into the TRRCVA calculation and evidence at Exhibit C, Tab 1, Schedule 4.

21. EGD has incorporated the impacts of this analysis and evidence in the 2010 earnings sharing calculation. EGD is seeking approval of the impacts of this analysis in each of the revised 2010 TRRCVA and 2010 ESMDA balances for which clearance is being requested at July 1, 2011 as well as the approval of the impact of this analysis in the 2011 TRRCVA and on what will be included within the 2012 Rate Adjustment calculations.

ONTARIO UTILITY CAPITAL STRUCTURE
HST IMPLEMENTATION/PST ELIMINATION ANALYSIS

		Col. 1	Col. 2	Col. 3
Line No.		Component	Indicated Cost Rate	Return Component
		%	%	%
1.	Long-term debt	59.65	7.31	4.36
2.	Short-term debt	1.68	4.12	0.07
3.		61.33		4.43
4.	Preference shares	2.67	5.00	0.13
5.	Common equity	36.00	8.39	3.02
6.		100.00		7.58

	($000's)	2010	2011	2012
7.	Ontario Utility Income	329.9	797.5	935.4
8.	Rate base	(3,910.4)	(12,003.2)	(17,239.2)
9.	Indicated rate of return	(8.44)%	(6.64)%	(5.43)%
10.	(Def.) / suff. in rate of return	(16.02)%	(14.22)%	(13.01)%
11.	Net (def.) / suff.	626.4	1,706.9	2,242.8
12.	Gross (def.) / suff.	907.8	2,379.0	3,041.1

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY RATE BASE
HST IMPLEMENTATION/PST ELIMINATION ANALYSIS

Line No.	($000's)	Col. 1 2010	Col. 2 2011	Col. 3 2012
	Property, plant, and equipment			
1.	Cost or redetermined value	(713.0)	(5,703.7)	(11,407.4)
2.	Accumulated depreciation	5.1	160.5	628.2
3.		(707.9)	(5,543.2)	(10,779.2)
	Allowance for working capital			
4.	Accounts receivable merchandise finance plan	-	-	-
5.	Accounts receivable rebillable projects	-	-	-
6.	Materials and supplies	-	-	-
7.	Mortgages receivable	-	-	-
8.	Customer security deposits	-	-	-
9.	Prepaid expenses	(27.5)	(110.0)	(110.0)
10.	Gas in storage	-	-	-
11.	Working cash allowance	(3,175.0)	(6,350.0)	(6,350.0)
12.		(3,202.5)	(6,460.0)	(6,460.0)
13.	Ontario utility rate base	(3,910.4)	(12,003.2)	(17,239.2)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY INCOME
HST IMPLEMENTATION/PST ELIMINATION ANALYSIS

Line No.	($000's)	Col. 1 2010	Col. 2 2011	Col. 3 2012
	Revenue			
1.	Gas sales	-	-	-
2.	Transportation of gas	-	-	-
3.	Transmission and compression	-	-	-
4.	Other operating revenue	-	-	-
5.	Other income	-	-	-
6.	Total revenue	-	-	-
	Costs and expenses			
7.	Gas costs	-	-	-
8.	Operation and Maintenance	(601.8)	(1,203.5)	(1,203.5)
9.	Depreciation and amortization	(33.4)	(307.3)	(628.0)
10.	Municipal and other taxes	-	-	-
11.	Total costs and expenses	(635.2)	(1,510.8)	(1,831.5)
12.	**Utility income before inc. taxes**	635.2	1,510.8	1,831.5
	Income taxes			
13.	Excluding interest shield	251.6	563.1	695.6
14.	Tax shield on interest expense	53.7	150.2	200.5
15.	Total income taxes	305.3	713.3	896.1
16.	**Ontario utility net income**	329.9	797.5	935.4

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
HST IMPLEMENTATION/PST ELIMINATION ANALYSIS

Line No.	($000's)	Col. 1 2010	Col. 2 2011	Col. 3 2012
1.	Utility income before income taxes	635.2	1,510.8	1,831.5
	Add Backs			
2.	Depreciation and amortization	(33.4)	(307.3)	(628.0)
3.	Large corporation tax	-	-	-
4.	Other non-deductible items	-	-	-
5.	Any other add back(s)	-	-	-
6.	Total added back	(33.4)	(307.3)	(628.0)
7.	Sub total - pre-tax income plus add backs	601.8	1,203.5	1,203.5
	Deductions			
8.	Capital cost allowance - Federal	(209.8)	(790.0)	(1,446.4)
9.	Capital cost allowance - Provincial	(209.8)	(790.0)	(1,446.4)
10.	Items capitalized for regulatory purposes	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-
12.	Amortization of share and debt issue expense	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-
15.	Any other deduction(s)	-	-	-
16.	Total Deductions - Federal	(209.8)	(790.0)	(1,446.4)
17.	Total Deductions - Provincial	(209.8)	(790.0)	(1,446.4)
18.	Taxable income - Federal	811.5	1,993.5	2,649.9
19.	Taxable income - Provincial	811.5	1,993.5	2,649.9
20.	Income tax provision - Federal	146.1	328.9	397.5
21.	Income tax provision - Provincial	105.5	234.2	298.1
22.	Income tax provision - combined	251.6	563.1	695.6
23.	Part V1.1 tax	-	-	-
24.	Investment tax credit	-	-	-
25.	Total taxes excluding tax shield on interest expense	251.6	563.1	695.6
	Tax shield on interest expense			
26.	Rate base as adjusted	(3,910.4)	(12,003.2)	(17,239.2)
27.	Return component of debt	4.43%	4.43%	4.43%
28.	Interest expense	(173.2)	(531.7)	(763.7)
29.	Combined tax rate	31.000%	28.250%	26.250%
30.	Income tax credit	53.7	150.2	200.5
31.	**Total income taxes**	305.3	713.3	896.1

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY REVENUE REQUIREMENT
HST IMPLEMENTATION/PST ELIMINATION ANALYSIS

Line No.	($000's)	Col. 1 2010	Col. 2 2011	Col. 3 2012
	Cost of capital			
1.	Rate base	(3,910.4)	(12,003.2)	(17,239.2)
2.	Required rate of return	7.58%	7.58%	7.58%
3.	Cost of capital	(296.4)	(909.8)	(1,306.7)
	Cost of service			
4.	Gas costs	-	-	-
5.	Operation and Maintenance	(601.8)	(1,203.5)	(1,203.5)
6.	Depreciation and amortization	(33.4)	(307.3)	(628.0)
7.	Municipal and other taxes	-	-	-
8.	Cost of service	(635.2)	(1,510.8)	(1,831.5)
	Misc. & Non-Op. Rev			
9.	Other operating revenue	-	-	-
10.	Other income	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-
	Income taxes on earnings			
12.	Excluding tax shield	251.6	563.1	695.6
13.	Tax shield provided by interest expense	53.7	150.2	200.5
14.	Income taxes on earnings	305.3	713.3	896.1
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	907.8	2,379.0	3,041.1
16.	Net (def.) / suff.	626.4	1,706.9	2,242.8
17.	Taxes on (def.) / suff.	(281.4)	(672.1)	(798.3)
18.	**Revenue requirement**	(907.7)	(2,379.4)	(3,040.4)
	Revenue at existing Rates			
19.	Gas sales	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0
22.	Rounding adjustment	0.1	(0.4)	0.7
23.	Revenue at existing rates	0.1	(0.4)	0.7
24.	**Gross revenue (def.) / suff.**	907.8	2,379.0	3,041.1

Witnesses: K. Culbert
R. Small

ALLOCATION OF COSTS
REGULATED AND UNREGULATED STORAGE ACTIVITIES

1. In accordance with the provisions of the EB-2010-0042 Settlement Agreement (Issue 13), this evidence addresses Enbridge's analysis of the appropriate allocation of the costs of regulated and unregulated gas storage activities. The analysis has been developed in light of the findings and comments of the Board in the Natural Gas Electricity Interface Review ("NGEIR") Decision (EB-2005-0551).

2. In the NGEIR Decision, the Board found that functional separation of unregulated and regulated storage operations is not necessary. The Board also recognized that, for a period of time prior to the NGEIR Decision, Union Gas Limited (Union) had been using a Board approved cost allocation methodology in order to separate costs of regulated and unregulated storage activities but that, as at the time of the Decision, Enbridge did not have any unregulated storage operations.

3. Unlike Union, it was not necessary for Enbridge to conduct a study of the storage assets that it owned at the time of the NGEIR Decision to try to determine the portion that was to be allocated to unregulated storage operations. All of Enbridge's then-existing storage assets were required to meet the storage, transmission and compression service needs of its in-franchise customers. Prior to their development, the underground storage capacities operated by Enbridge at the time of the NGEIR Decision had been tested against other available service alternatives, in accordance with the requirements and procedures applicable to regulated storage activities.

New Storage Assets

4. Following the NGEIR Decision, Enbridge identified and developed facilities to create new storage capacities. The costs of these new storage capacities have been charged to the accounts of the unregulated storage operations. The incremental costs of projects undertaken to upgrade existing assets, in order to support the capacity requirements of the unregulated storage operations, have been charged to the unregulated storage operations. The cost of projects required to maintain the storage capacities required by the traditional, in-franchise customers have been charged to regulated storage operations.

5. The costs of unregulated capital projects include all of the material and contractor costs that are attributable to unregulated storage operations. Time spent by Enbridge staff on the design and construction of these assets is tracked and then charged to the unregulated projects at hourly rates that include corporate Administrative and General (A&G) overhead as well as the expected cost of the employee compensation that is in place.

Storage Operating & Maintenance Costs

6. The total Operating and Maintenance (O&M) costs of the integrated storage activity must be allocated between unregulated and regulated storage operations. Enbridge has analyzed the appropriate allocation of costs in order to develop an allocation that is both practical and fair. It has adopted a methodology that is based upon the proportionate shares of the storage capacities that are available and operated on behalf of each activity.

7. Enbridge had originally considered a method whereby some O&M costs would have been charged to unregulated storage operations, based on the ownership and operation of the underlying assets, similar to the approach taken by Union Gas, with the balance of the costs allocated on the basis of the relative storage capacities of the unregulated and regulated operations.

8. However, this method was not practical for Enbridge because of the different asset circumstances of the two companies at the time of the NGEIR Decision. In addition it was felt that, as future enhancements to the existing storage assets are made, it will become progressively more difficult to track the ownership of the underlying assets, making this methodology more and more unwieldy, and less transparent, over time. As a the result, Enbridge's analysis led to the conclusion that a methodology based on the relative amounts of storage capacity and storage activity is more appropriate for Enbridge in the allocation of its O&M expenses.

9. Generally, the allocation methodology resulting from Enbridge's analysis recognizes that some O&M costs vary with the level of storage activity whereas others do not. The costs that do not vary with day to day activity are allocated between unregulated and regulated storage operations based upon their respective share of the total turnover capacity. On this basis, both operations pay a share of costs that do not vary with day to day activity. The costs that vary with the level of storage activity are allocated based on the relative levels of the actual injection and withdrawal volumes of the two operations.

10. This methodology is fair and transparent and relatively easy to administer. It fairly allocates O&M costs to the two operations, given that the injection/withdrawal activity characteristics of the two have some fundamental differences. Regulated

storage follows the more traditional, single storage cycle of its customers' needs, whereas the unregulated operation has a higher gas turnover profile with the potential for relatively high injection/withdrawal activity at times when there may not be a high level of injection/withdrawal for regulated storage operations.

11. Enbridge's allocated storage O&M costs include all labour, materials and contractor costs that are associated with its storage operations in Lambton and Kent counties. The labour costs charged to unregulated storage operations include an allocation of A&G overheads from both EGDI in Toronto and EI in Calgary. The allocated O&M costs also include the total cost of annual land rights rentals and municipal taxes of the integrated storage operation.

Unregulated Business Development Direct Costs

12. In addition to the appropriate allocation of actual storage operation costs, there are other O&M costs that are directly attributable to the unregulated storage operation. Staff in Enbridge's Toronto offices is involved in the day to day commercial and administrative requirements of the business, as well as management, planning and development needs of the unregulated storage operation. The costs of these activities are allocated to the unregulated storage operation, including all direct labour, materials and contractor/consultant costs that are specific to the unregulated business, and not required by the integrated storage operation.

A&G Overhead

13. A&G costs, facilities and IT overheads are allocated using labour (FTEs) as the basis for allocation. The allocated A&G includes a broad range of costs such as

finance, regulatory, legal, human resources, employee health & safety, a return on equity and depreciation cost related to capital use.

14. In addition to these EGDI overheads, Enbridge Inc. also allocates overhead among its various subsidiaries and affiliates. Some of this overhead is charged directly to unregulated storage operations and another portion is charged to EGDI. Some of the latter portion finds its way to unregulated storage through the A&G allocations discussed above.

Fuel Gas

15. Since the commencement of unregulated gas storage services, Enbridge has charged the unregulated storage operation for its share of the total cost of gas used for fuel. This cost has been calculated by pro-rating the actual monthly fuel volumes used in storage, based on the amounts of monthly regulated and unregulated storage activities, and then charging each operation for its pro-rated volume based on the previous October QRAM reference price. In this way both the unregulated and regulated storage operations bear only their own share of the cost of fuel gas.

Lost and Unaccounted For Gas

16. Similar to the need to recover the cost of fuel gas, as discussed above, the unregulated storage business also has to ensure that it recovers a volume of gas to replace any Lost and Unaccounted For (LUF) gas volumes that might result from its storage activities. The unregulated storage operation charges its customers an ‘in-kind’ LUF volume amount based on their storage injection and withdrawal

activity. The in-kind charge uses the same LUF replacement ‘factor’ that underlies the current LUF replacement volumes allowed by the Board.

Depreciation

17. Enbridge’s unregulated storage assets have been separated from the regulated storage assets in a distinct business with a separate set of accounts. The account classifications, and the relevant depreciation rates used, mirror those used for the regulated storage assets (although a review of these depreciation rates is currently underway). The rates currently used are shown in the table below.

Account Number	Account Description	Depreciation Rate (%)
451	Land Rights	2.10
452	Structures & Improvements	2.60
453	Wells	4.60
454	Well Equipment	3.10
455	Field Lines	2.60
456	Compressor Equipment	2.20
457	Regulating Equipment	3.60

Results

18. Based on its analysis, Enbridge has concluded that the cost allocation approach described in this evidence is transparent, practical and fair. In the Appendices that follow, Enbridge has set out the results of its allocation of costs between unregulated and regulated storage operations from 2007 to 2010.

Witnesses: K. Culbert
B. Pilon

APPENDIX I

ENBRIDGE STORAGE ACTIVITIES

	2007	2008	2009	2010
Unregulated Storage Capacity as of April 1 (Bcf)	-	3.0	5.5	7.5
Regulated Storage Capacity (Bcf)	98.0	98.0	98.0	98.0
Total Storage Capacity	98.0	101.0	103.5	105.5

($ millions)	2007	2008	2009	2010
Direct Unregulated Storage O&M	0.24	0.30	0.78	0.77
Allocated Storage - Labour & Overheads	-	0.03	0.10	0.25
- Operations & Maintenance	-	0.01	0.11	0.21
- Administration & General	-	0.01	0.13	0.23
Total Unregulated Storage O&M	0.24	0.35	1.12	1.46

	2007	2008	2009	2010
O&M Allocated to Unregulated	-	0.05	0.34	0.69
O&M Regulated Storage	8.45	8.22	8.56	9.26
Total O&M for Storage	8.45	8.27	8.90	9.95

Propery taxes are included in above numbers

Witnesses: K. Culbert
B. Pilon

APPENDIX II

ALLOCATION OF STORAGE O&M COSTS TO UNREGULATED LOB

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: JAN-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity % of Total
Regulated	98.392	92.95%	96.55%
Un-regulated	7.46	6.25%	3.45%
	105.852	99.20%	100.00%

COST CENTRE=25123 (STORAGE MAINTENANCE)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $	Overhead Factor
CONTROLLABLE COSTS							
60101 BASE PAY	29,087	100%	100%	49,453	0%	0	70.0%
60105 HOURLY PAYROLL	42,140	100%	100%	71,646	0%	0	70.0%
60109 TEMPORARY PAYRO	0	100%	100%	0	0%	0	70.0%
60117 VACATION PAY	4,178	100%	100%	7,103	0%	0	70.0%
60129 SCHEDULED OVERT	15,245	100%	40%	10,368	60%	15,552	70.0%
60131 STATUTORY HOLID	3,644	100%	100%	6,195	0%	0	70.0%
60133 SICK PAY	621	100%	100%	1,056	0%	0	70.0%
60145 OTHER SALARY EX	0	100%	100%	0	0%	0	70.0%
TOTAL LABOUR	**94,915**			**145,821**		**15,552**	
61009 SAFETY RELATED	5,197	100%	40%	2,079	60%	3,118	
61299 OTHER MATERIALS	28,940	100%	40%	11,576	60%	17,364	
61601 CONTRACT SERVIC	34,429	100%	40%	13,772	60%	20,657	
NON-LABOUR COST CENTRE COSTS	**68,566**			**27,426**		**41,140**	
INTERNAL COST RECOVERIES							
79951 CAPITAL PROJECT	0	100%	100%	0	100%	0	0%
79966 VARIABLE INTERN	(1,600)	100%	100%	(1,600)	100%	(1,600)	0%
79967 OTHER RECOVERIE CAPITAL	0	100%	100%	0	100%	0	0%
TOTAL COST RECOVERIES	(1,600)			(1,600)		(1,600)	
TOTAL NET COST CENTRE COSTS	**161,881**			**171,648**		**55,091**	
CHARGES TO UN-REGULATED				**10,728**		**1,901**	
						12,629	

ANALYSIS OF CORPORATE COST ALLOCATION TREATMENT REQUIRED IN UTILITY EARNINGS

Background of Required Treatment

1. In calculating utility earnings, the current practice for determining the level of corporate cost allocable amounts allowed within utility operating and maintenance costs is that established through the Board Approved Regulatory Cost Allocation Methodology ("RCAM"). The level of corporate costs actually allocated to EGD, is determined through a different process, the Corporate Cost Allocation Methodology ("CAM"). As a result, within the process of establishing utility earnings and earnings sharing amounts, the difference between the level of corporate costs within EGD's corporate financial results derived through CAM and the RCAM methodology allowed amount is eliminated from utility operating and maintenance ("O&M") costs.

2010 CAM Process Established Amounts Allocable to EGD

2. In each year's budgeting cycle, the corporate cost allocations determined through the CAM methodology are established and sent to EGD for inclusion into EGD's O&M budget. CAM amounts are comprised of fixed administration, general, and direct costs. Once CAM budget amounts are established, they are input into specific natural accounts and cost centres within EGD's budget. The total CAM amount established in EGD's 2010 Budget is $36.7 million.

2010 RCAM Process Established Amounts Allocable to EGD

3. As well each year, the Company undertakes an update of the RCAM methodology as approved by the Board to establish amounts relevant to that fiscal year. The Company's ongoing review of the RCAM methodology and related processes, includes the review and input of intervenor groups. Service schedules relating to

RCAM are carefully reviewed and revised by EGD on an annual basis. The review results in the appropriate level of specific services, activities and/or departmental charges from EI. The total RCAM amount established for 2010 is $24.3 million.

Variance of Actual CAM Amounts Allocated Versus Year-end Identified Amounts

4. At the time of the Fiscal 2010 year end process, an automated macro CAM template was used to extract actual CAM data from financial system accounts which were expected to match the specific accounts where CAM was budgeted. However, as a result of a new account number being used in the establishment of the CAM budget, which was not identified and incorporated into the automated macro actual data extract, the level of actual data extracted and thought to be representative of the CAM allocable amounts was incorrect. The amount extracted at the time of the year end process totaled $39.1 million and in determining utility earnings for earnings sharing purposes, the difference of $15.0 million, between the $39.1 million which was thought to be the correct CAM allocated amount and the RCAM process established amount of $24.3 million, was eliminated from O&M.

5. Subsequent to year end, a full reconciliation between all the general ledger accounts where the CAM data was budgeted and the accounts within which the actual data extract at year end occurred was conducted. The reconciliation identified that the correct CAM amount, which should have been extracted from actual results if the automated macro had been appropriately adjusted, is $36.7 million. In order to ensure that the appropriate RCAM level of $24.3 million is reflected in utility earnings and the earnings sharing result, an amount of $12.4 million should have been eliminated from O&M ($36.7M - $24.3M) instead of the $15.0 million that was eliminated in arriving at the year-end estimated utility

Witnesses: K. Culbert
R. Lei
L. Liauw

earnings and earnings sharing accrual. The impact of this change is explained in evidence at Exhibit B, Tab 1, Schedule 1, Appendix A

UTILITY RATE BASE

COMPARISON OF 2010 HISTORICAL YEAR TO 2009 HISTORICAL YEAR

Line No.		Col. 1 2010 Historical Year	Col. 2 2009 Historical Year	Col. 3 Difference
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	5,807.2	5,500.5	306.7
2.	Accumulated depreciation	(2,235.7)	(2,089.5)	(146.2)
3.	Net property, plant, and equipment	3,571.5	3,411.0	160.5
	Allowance for Working Capital			
4.	Accounts receivable merchandise finance plan	-	-	-
5.	Accounts receivable rebillable projects	0.5	(0.1)	0.6
6.	Materials and supplies	24.1	26.5	(2.4)
7.	Mortgages receivable	0.6	0.7	(0.1)
8.	Customer security deposits	(67.1)	(53.3)	(13.8)
9.	Prepaid expenses	1.3	1.5	(0.2)
10.	Gas in storage	310.1	406.5	(96.4)
11.	Working cash allowance	(3.3)	1.6	(4.9)
12.	Total Working Capital	266.2	383.4	(117.2)
13.	Utility Rate Base	3,837.7	3,794.4	43.3

Witnesses: K. Culbert
R. Small

UTILITY RATE BASE
COMPARISON OF 2009 HISTORICAL YEAR TO 2008 HISTORICAL YEAR

Line No.		Col. 1 2009 Historical Year	Col. 2 2008 Historical Year	Col. 3 Difference
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	5,500.5	5,225.4	275.1
2.	Accumulated depreciation	(2,089.5)	(1,955.8)	(133.7)
3.	Net property, plant, and equipment	3,411.0	3,269.6	141.4
	Allowance for Working Capital			
4.	Accounts receivable merchandise finance plan	-	-	-
5.	Accounts receivable rebillable projects	(0.1)	0.2	(0.3)
6.	Materials and supplies	26.5	28.9	(2.4)
7.	Mortgages receivable	0.7	0.8	(0.1)
8.	Customer security deposits	(53.3)	(44.8)	(8.5)
9.	Prepaid expenses	1.5	1.7	(0.2)
10.	Gas in storage	406.5	518.6	(112.1)
11.	Working cash allowance	1.6	4.2	(2.6)
12.	Total Working Capital	383.4	509.6	(126.2)
13.	Utility Rate Base	3,794.4	3,779.2	15.2

Witnesses: K. Culbert
R. Small

UTILITY PROPERTY, PLANT, AND EQUIPMENT
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	282.2	(102.3)	179.9
2.	Distribution plant	5,152.7	(2,011.4)	3,141.3
3.	General plant	379.2	(121.5)	257.7
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	5,814.6	(2,235.7)	3,578.9
6.	Plant held for future use	1.7	(0.9)	0.8
7.	Sub- total	5,816.3	(2,236.6)	3,579.7
8.	Affiliate Shared Assets Value	(9.1)	0.9	(8.2)
9.	Total property, plant, and equipment	5,807.2	(2,235.7)	3,571.5

Witnesses: K. Culbert
R. Small

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2010	Col. 5 Regulatory Adjustments	Col. 6 Utility Balance Dec.2010	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	4.2	-	-	4.2	-	4.2	4.2
2.	Land and gas storage rights (450/451)	39.8	0.9	-	40.7	-	40.7	39.9
3.	Structures and improvements (452.00)	10.9	3.2	-	14.1	-	14.1	11.1
4.	Wells (453.00)	29.9	8.6	-	38.5	-	38.5	31.3
5.	Well equipment (454.00)	8.4	0.5	-	8.9	-	8.9	8.6
6.	Field Lines (455.00)	46.3	0.3	-	46.6	-	46.6	46.3
7.	Compressor equipment (456.00)	87.9	2.5	-	90.4	-	90.4	88.5
8.	Measuring and regulating equipment (457.00)	11.4	0.1	-	11.5	-	11.5	11.4
9.	Base pressure gas (458.00)	40.9	-	-	40.9	-	40.9	40.9
10.	Total	279.7	16.1	-	295.8	-	295.8	282.2

Witnesses: K. Culbert
R. Small

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2010	Col. 6 Regulatory Adjustments	Col. 7 Utility Balance Dec.2010	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(2.0)	(0.2)	-	-	(2.2)	-	(2.2)	(2.1)
2.	Land and gas storage rights (451.00)	(19.4)	(0.8)	-	-	(20.2)	-	(20.2)	(19.8)
3.	Structures and improvements (452.00)	(4.4)	(0.2)	-	-	(4.6)	-	(4.6)	(4.5)
4.	Wells (453.00)	(16.5)	(1.5)	-	0.1	(17.9)	-	(17.9)	(17.2)
5.	Well equipment (454.00)	(4.1)	(0.3)	-	-	(4.4)	-	(4.4)	(4.3)
6.	Field Lines (455.00)	(19.6)	(1.2)	-	-	(20.8)	-	(20.8)	(20.2)
7.	Compressor equipment (456.00)	(28.5)	(1.9)	-	-	(30.4)	-	(30.4)	(29.4)
8.	Measuring and regulating equipment (457.00)	(4.6)	(0.4)	-	-	(5.0)	-	(5.0)	(4.8)
9.	Total	(99.1)	(6.5)	-	0.1	(105.5)	-	(105.5)	(102.3)

Witnesses: K. Culbert
R. Small

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2010	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2010	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	11.4	9.0	-	20.4	-	20.4	11.8
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	7.4	-	-	7.4	-	7.4	7.4
4.	Structures and improvements (472.00)	77.4	5.1	(0.5)	82.0	(0.3)	81.7	79.0
5.	Services, house reg & meter install. (473/474)	1,949.5	104.4	(29.3)	2,024.6	-	2,024.6	1,982.4
6.	NGV station compressors (476)	2.2	0.4	-	2.6	-	2.6	2.4
7.	Meters (478)	363.6	16.7	(12.6)	367.7	-	367.7	361.0
8.	Sub-total	2,411.5	135.6	(42.4)	2,504.7	(0.3)	2,504.4	2,444.0
9.	Mains (475)	2,347.3	136.6	(4.9)	2,479.0	-	2,479.0	2,400.4
10.	Measuring and regulating equip. (477)	304.0	12.4	(2.0)	314.4	-	314.4	308.3
11.	Sub-total	2,651.3	149.0	(6.9)	2,793.4	-	2,793.4	2,708.7
12.	Total	5,062.8	284.6	(49.3)	5,298.1	(0.3)	5,297.8	5,152.7

Note 1: The Column 5 adjustment is the elimination of non-utility corporate branding costs.

Witnesses: K. Culbert
R. Small

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2010	Col. 6 Regulatory Adjustment (Note 1)	Col. 7 Utility Balance Dec.2010	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(0.7)	(0.4)	-	-	(1.1)	-	(1.1)	(0.9)
2.	Structures and improvements (472.00)	(5.1)	(2.1)	0.5	1.5	(5.2)	0.1	(5.1)	(6.0)
3.	Services, house reg & meter install. (473/474)	(823.9)	(90.1)	29.3	12.2	(872.5)	-	(872.5)	(854.7)
4.	NGV station compressors (476)	(1.5)	(0.1)	-	-	(1.6)	-	(1.6)	(1.5)
5.	Meters (478)	(95.8)	(9.0)	12.6	(0.4)	(92.6)	-	(92.6)	(93.3)
6.	Mains (475)	(858.5)	(100.9)	4.9	6.5	(948.0)	0.1	(947.9)	(903.9)
7.	Measuring and regulating equip. (477)	(144.6)	(16.0)	2.0	-	(158.6)	-	(158.6)	(151.1)
8.	Total	(1,930.1)	(218.6)	49.3	19.8	(2,079.6)	0.2	(2,079.4)	(2,011.4)

Note 1: The Column 6 adjustments are the removal of depreciation provisions on non-utility corporate branding costs, and on Mississauga Southern Link disallowances (EBRO 473 & 479).

Witnesses: K. Culbert
R. Small

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2010	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2010	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	4.6	0.2	-	4.8	(0.2)	4.6	4.5
2.	Office furniture and equipment (483.00)	20.1	1.9	(3.9)	18.1	-	18.1	18.4
3.	Transportation equipment (484.00)	39.8	2.8	(1.6)	41.0	(0.1)	40.9	39.1
4.	NGV conversion kits (484.01)	7.3	0.4	-	7.7	-	7.7	7.5
5.	Heavy work equipment (485.00)	17.3	2.7	(0.7)	19.3	-	19.3	17.2
6.	Tools and work equipment (486.00)	31.9	2.6	(0.3)	34.2	-	34.2	32.2
7.	Rental equipment (487.70)	1.0	-	-	1.0	-	1.0	1.0
8.	NGV rental compressors (487.80)	6.0	0.4	(1.5)	4.9	-	4.9	5.7
9.	NGV cylinders (484.02 and 487.90)	2.2	0.1	-	2.3	-	2.3	2.3
10.	Communication structures & equip. (488)	3.0	-	-	3.0	-	3.0	3.0
11.	Computer equipment (490.00)	124.9	29.2	(31.3)	122.8	-	122.8	121.0
12.	CIS (491.00)	127.4	(0.3)	-	127.1	-	127.1	127.3
13.	Total	385.5	40.0	(39.3)	386.2	(0.3)	385.9	379.2

Note 1: The Column 5 adjustments are the elimination of non-utility corporate branding costs.

Witnesses: K. Culbert
R. Small

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2010	Col. 6 Regulatory Adjustment (Note 1)	Col. 7 Utility Balance Dec.2010	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	(3.4)	(0.3)	-	-	(3.7)	0.1	(3.6)	(3.4)
2.	Office furniture and equipment (483.00)	(12.1)	(0.8)	3.9	-	(9.0)	-	(9.0)	(10.5)
3.	Transportation equipment (484.00)	(7.6)	(1.7)	1.6	(0.1)	(7.8)	-	(7.8)	(7.8)
4.	NGV conversion kits (484.01)	(4.4)	(0.2)	-	-	(4.6)	-	(4.6)	(4.5)
5.	Heavy work equipment (485.00)	(6.8)	(0.6)	0.7	(0.1)	(6.8)	-	(6.8)	(6.8)
6.	Tools and work equipment (486.00)	(12.5)	(0.9)	0.3	-	(13.1)	-	(13.1)	(12.8)
7.	Rental equipment (487.70)	(0.9)	(0.1)	-	-	(1.0)	-	(1.0)	(0.9)
8.	NGV rental compressors (487.80)	(4.2)	(0.4)	1.5	-	(3.1)	-	(3.1)	(3.9)
9.	NGV cylinders (484.02 and 487.90)	(1.4)	(0.1)	-	-	(1.5)	-	(1.5)	(1.5)
10.	Communication structures & equip. (488)	(2.1)	(0.1)	-	-	(2.2)	-	(2.2)	(2.1)
11.	Computer equipment (490.00)	(55.5)	(24.1)	31.3	-	(48.3)	-	(48.3)	(57.9)
12.	CIS (491.00)	(3.0)	(12.7)	-	-	(15.7)	-	(15.7)	(9.4)
13.	Total	(113.9)	(42.0)	39.3	(0.2)	(116.8)	0.1	(116.7)	(121.5)

Note 1: The Column 6 adjustments are the elimination of non-utility corporate branding costs.

Witnesses: K. Culbert
R. Small

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2010	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2010	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

Witnesses: K. Culbert
R. Small

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2010	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2010	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

Witnesses: K. Culbert
R. Small

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2010	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2010	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

Witnesses: K. Culbert
R. Small

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2010 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2009	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2010	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2010	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(0.9)	(0.1)	-	-	(1.0)	-	(1.0)	(0.9)
2.	Total	(0.9)	(0.1)	-	-	(1.0)	-	(1.0)	(0.9)

Witnesses: K. Culbert
R. Small

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ACTUAL 2010 AND ACTUAL 2009

Item No.		Col. 1 Actuals 2010 ($Millions)	Col. 2 Actuals 2009 ($Millions)	Col. 3 2010 Over/(Under) 2009 ($Millions)
A.	Customer Related			
1.1.1	Sales Mains	46.7	48.2	(1.5)
1.1.2	Services	52.6	48.7	3.9
1.1.3	Meters and Regulation	8.3	11.9	(3.6)
1.1.4	Customer Related Distribution Plant	107.6	108.8	(1.2)
1.1.5	NGV Rental Equipment	0.2	0.2	-
1.1	TOTAL CUSTOMER RELATED CAPITAL	107.8	109.0	(1.2)
B.	System Improvements and Upgrades			
1.2.1	Mains - Relocations	13.2	8.0	5.2
1.2.2	- Replacement	55.7	49.9	5.8
1.2.3	- Reinforcement	14.0	16.8	(2.8)
1.2.4	Total Improvement Mains	82.9	74.7	8.2
1.2.5	Services - Relays	45.8	37.0	8.8
1.2.6	Regulators - Refits	6.4	7.7	(1.3)
1.2.7	Measurement and Regulation	10.3	9.2	1.1
1.2.8	Meters	13.1	15.9	(2.8)
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	158.5	144.5	14.0
C.	General and Other Plant			
1.3.1	Land, Structures and Improvements	14.0	2.9	11.1
1.3.2	Office Furniture and Equipment	1.9	0.9	1.0
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	6.5	11.4	(4.9)
1.3.4	Tools and Work Equipment	2.5	2.3	0.2
1.3.5	Computers and Communication Equipment	32.0	24.8	7.2
1.3	TOTAL GENERAL AND OTHER PLANT	56.9	42.3	14.6
D.	Underground Storage Plant	14.7	4.6	10.1
E.	Customer Information System (CIS)	(0.3)	48.7	(49.0)
F.	TOTAL CAPITAL EXPENDITURES	337.6	349.1	(11.5)

Witnesses: L. Au
D. Kelly

ACTUAL 2010 CAPITAL EXPENDITURE WORKSHEET

Item No.		Col. 1 Business as Usual ($Millions)	Col. 2 Safety and Integrity Initiatives ($Millions)	Col. 3 Leave to Construct Projects ($Millions)	Col. 4 Other Additional Initiatives ($Millions)	Col. 5 Total Actual 2010 ($Millions)
A.	Customer Related					
1.1.1	Sales Mains	42.1		4.6		46.7
1.1.2	Services	52.6				52.6
1.1.3	Meters and Regulation	8.3				8.3
1.1.4	Customer Related Distribution Plant	103.0	-	4.6	-	107.6
1.1.5	NGV Rental Equipment	0.2				0.2
						-
1.1	TOTAL CUSTOMER RELATED CAPITAL	103.2	-	4.6	-	107.8
B.	System Improvements and Upgrades					
1.2.1	Mains - Relocations	13.2				13.2
1.2.2	- Replacement	49.2	6.5			55.7
1.2.3	- Reinforcement	8.3		5.2	0.5	14.0
1.2.4	Total Improvement Mains	70.7	6.5	5.2	0.5	82.9
1.2.5	Services - Relays	37.8	8.0			45.8
1.2.6	Regulators - Refits	6.4				6.4
1.2.7	Measurement and Regulation	10.3				10.3
1.2.8	Meters	13.1				13.1
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	138.3	14.5	5.2	0.5	158.5
C.	General and Other Plant					-
1.3.1	Land, Structures and Improvements	5.0	9.0			14.0
1.3.2	Office Furniture and Equipment	1.9				1.9
1.3.3	Transp/Heavy Work/NGV Compressor Equipr	6.5				6.5
1.3.4	Tools and Work Equipment	2.5				2.5
1.3.5	Computers and Communication Equipment	32.0				32.0
1.3	TOTAL GENERAL AND OTHER PLANT	47.9	9.0	-	-	56.9
D.	Underground Storage Plant	14.7				14.7
E.	Customer Information System (CIS)				(0.3)	(0.3)
F.	TOTAL CAPITAL EXPENDITURES	304.1	23.5	9.8	0.2	337.6

Project Details:

		Col. 2	Col. 3	Col. 4	Col. 5
2.1	Incremental Cast Iron Replacement	12.3			12.3
2.2	Kerotest Valve Replacement	1.6			1.6
2.3	Inside regulators	0.6			0.6
2.4	Technical Training Facility	9.0			9.0
3.1	York Energy Centre		4.6		4.6
3.2	Scarborough Reinforcement		4.7		4.7
3.3	Bathurst Gate Station Reinforcement		0.5		0.5
4.1	Energy Technology			0.5	0.5
4.2	Customer Information System (CIS)			(0.3)	(0.3)
Sub total Additional Initiatives		23.5	9.8	0.2	33.5

Witnesses: L. Au
D. Kelly

EXPLANATION OF MAJOR CHANGES

IN ACTUAL 2010 UTILITY CAPITAL EXPENDITURES
FROM ACTUAL 2009 UTILITY CAPITAL EXPENDITURES

The 2010 Actual was $337.6 million, which is $11.5 million or 3.3% less than the 2009 Actual of $349.1 million. The capital expenditure decrease was primarily related to decreased requirements in Customer Information System ("CIS") and customer related expenditures. This was partially offset by increased requirements for general plant, storage plant and system improvements and upgrades. The major categories showing significant variances are explained below:

Item No.

1.1.4 Customer Related Distribution Plant – Decrease $1.2 Million

The decrease in customer related plant was driven by a lower allocation of indirect costs ($4.7M) and sales mains related to less commercial industrial activity. This was primarily due to the 2009 completion of the Northland Thorold Power generation project which was partially offset by 2010 expenditures for York Energy Centre ($2.6M). The decrease was partially offset by increased expenditures ($6.1M) due to the higher number of customers added in 2010 (36,902) compared to 2009 (32,080).

1.2.4 Improvement Mains – Increase $8.2 Million

The increase reflects higher relocation and replacement activity ($8.5M) in 2010 relative to 2009. This was primarily due to requirements in GTA regions and the Ottawa area as well as increased safety and integrity initiatives related to Kerotest Valve replacement and inside regulator programs ($1.5M). There was

Witnesses: L. Au
D. Kelly

also a higher allocation of indirect costs relative to 2009 ($1.0M). These increases were partially offset by a decrease in reinforcement activity ($2.8M) mainly due to the timing of the Scarborough Reinforcement and Bathurst Gate Reinforcement projects.

1.2.5 Service Relays – Increase $8.8 Million

The increase was primarily due to higher service relay requirements in 2010 ($7.0M) which is reflective of the increased improvement main activity. There was also a higher allocation of indirect costs ($1.8M).

1.2.6 Regulator Refits – Decrease $1.3 Million

The decrease was due to less refit requirements relative to 2009. This activity is mandated by the government inspection meter exchange program, which were lower in 2010.

1.2.7 Measurement and Regulation – Increase $1.1 Million

The increase was primarily due to more system regulation requirements relative to 2009. The increase was driven by a more aggressive workload in 2010 and was also impacted by increased material costs.

1.2.8 Meters – Decrease $2.8 Million

The decrease was primarily due to less meter purchases ($1.0M) and a lower allocation of indirect costs ($1.8M) relative to 2009.

C. General and Other Plant – Increase $14.6 Million

The actual spending in this category increased relative to 2009 actual spending. Land purchased for the Distribution Training and Operations facility accounted for

$9.0M of the increase. In addition, structures and improvement requirements increased by $2.1M mainly due to improvements completed at Victoria Park Centre (VPC). Computer equipment expenditures increased by $7.2M which was mainly due to software requirements. Furniture requirements increased by $1.0M. The variance was partially offset by decreased requirements in Transportation and Heavy Work Equipment ($4.9M).

D. Underground Storage Plant – Increase $10.1 million

The increase in storage plant expenditures reflects the completion and on-going efforts of several plant initiatives. The 3D Seismic initiative commenced in 2010 with expenditures of $3.9M. This technology allows for a more comprehensive understanding of the Company's storage pools. The warehouse and maintenance shop was completed in 2010 at a cost of $2.8M. A further increase of $2.1M was due to the Tecumseh/Wilkesport Well completion. The remaining increase was primarily due to a higher allocation of indirect costs ($0.9M) and 2010 land purchase related to compliance with emissions testing ($0.4M).

E. Customer Information System (CIS) – Decrease $49.0 million

CIS was a multi-year project that commenced in 2007. CIS had separate approval process with an approved spending of approximately $120M. At the end of 2009 the life to date spend was $127.5 million. The project variance was due to higher system integrator costs and higher interest during construction costs resulting from a delayed implementation and higher interest rates. The $0.3M credit in 2010 reflects an overestimation of 2009 management fees.

Witnesses: L. Au
D. Kelly

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ACTUAL 2009 AND ACTUAL 2008

Item No.		Col. 1 Actuals 2009 ($Millions)	Col. 2 Actuals 2008 ($Millions)	Col. 3 2009 Over/(Under) 2008 ($Millions)
A.	Customer Related			
1.1.1	Sales Mains	48.2	60.6	(12.4)
1.1.2	Services	48.7	49.3	(0.6)
1.1.3	Meters and Regulation	11.9	9.7	2.2
1.1.4	Customer Related Distribution Plant	108.8	119.6	(10.8)
1.1.5	NGV Rental Equipment	0.2	0.3	(0.1)
1.1	TOTAL CUSTOMER RELATED CAPITAL	109.0	119.9	(10.9)
B.	System Improvements and Upgrades			
1.2.1	Mains - Relocations	8.0	14.8	(6.8)
1.2.2	- Replacement	49.9	58.8	(8.9)
1.2.3	- Reinforcement	16.8	16.7	0.1
1.2.4	Total Improvement Mains	74.7	90.3	(15.6)
1.2.5	Services - Relays	37.0	30.4	6.6
1.2.6	Regulators - Refits	7.7	3.5	4.2
1.2.7	Measurement and Regulation	9.2	13.4	(4.2)
1.2.8	Meters	15.9	18.9	(3.0)
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	144.5	156.5	(12.0)
C.	General and Other Plant			
1.3.1	Land, Structures and Improvements	2.9	3.4	(0.5)
1.3.2	Office Furniture and Equipment	0.9	1.0	(0.1)
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	11.4	11.0	0.4
1.3.4	Tools and Work Equipment	2.3	3.6	(1.3)
1.3.5	Computers and Communication Equipment	24.8	18.3	6.5
1.3	TOTAL GENERAL AND OTHER PLANT	42.3	37.3	5.0
D.	Underground Storage Plant	4.6	5.9	(1.3)
E.	Customer Information System (CIS)	48.7	46.4	2.3
F.	TOTAL CAPITAL EXPENDITURES	349.1	366.0	(16.9)

Witnesses: L. Au
D. Kelly

ACTUAL 2009 CAPITAL EXPENDITURE WORKSHEET

Item No.		Col. 1 Business as Usual ($Millions)	Col. 2 Safety and Integrity Initiatives ($Millions)	Col. 3 Leave to Construct Projects ($Millions)	Col. 4 Other Additional Initiatives ($Millions)	Col. 5 Total Actual 2009 ($Millions)
A.	Customer Related					
1.1.1	Sales Mains	41.0		7.2		48.2
1.1.2	Services	48.7				48.7
1.1.3	Meters and Regulation	11.9				11.9
1.1.4	Customer Related Distribution Plant	101.6	-	7.2	-	108.8
1.1.5	NGV Rental Equipment	0.2				0.2
						-
1.1	TOTAL CUSTOMER RELATED CAPITAL	101.8	-	7.2	-	109.0
B.	System Improvements and Upgrades					
1.2.1	Mains - Relocations	8.0				8.0
1.2.2	- Replacement	43.9	6.0			49.9
1.2.3	- Reinforcement	9.2		7.6		16.8
1.2.4	Total Improvement Mains	61.1	6.0	7.6	-	74.7
1.2.5	Services - Relays	28.0	9.0			37.0
1.2.6	Regulators - Refits	7.2	0.5			7.7
1.2.7	Measurement and Regulation	8.9			0.3	9.2
1.2.8	Meters	15.9				15.9
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	121.1	15.5	7.6	0.3	144.5
C.	General and Other Plant					-
1.3.1	Land, Structures and Improvements	2.9				2.9
1.3.2	Office Furniture and Equipment	0.9				0.9
1.3.3	Transp/Heavy Work/NGV Compressor Equipme	11.4				11.4
1.3.4	Tools and Work Equipment	2.3				2.3
1.3.5	Computers and Communication Equipment	24.8				24.8
1.3	TOTAL GENERAL AND OTHER PLANT	42.3	-	-	-	42.3
D.	Underground Storage Plant	4.6				4.6
E.	Customer Information System (CIS)	-			48.7	48.7
F.	TOTAL CAPITAL EXPENDITURES	269.8	15.5	14.8	49.0	349.1

Project Details:

	Col. 2	Col. 3	Col. 4	Col. 5
2.1 Incremental Accelerated Cast Iron Replacement	14.3			14.3
2.2 Kerotest Valve Replacement	0.3			0.3
2.3 S&R Regulator Replacement	0.5			0.5
2.4 Inside regulators	0.4			0.4
3.1 Portlands Energy Power Generation		1.1		1.1
3.2 Northland Thorold Power		4.0		4.0
3.3 York Energy Centre		0.4		0.4
3.4 Goreway Power Generation		0.1		0.1
3.5 Other Power Generation		0.1		0.1
3.6 Alfred and Plantagenet		1.5		1.5
3.7 Scarborough Reinforcement		5.3		5.3
3.8 Bathurst Gate Station Reinforcement		2.3		2.3
4.1 Fuel Cell Technology			0.3	0.3
4.2 Customer Information System (CIS)			48.7	48.7
Sub total Additional Initiatives	15.5	14.8	49.0	79.3

Witnesses: L. Au
D. Kelly

EXPLANATION OF MAJOR CHANGES

IN ACTUAL 2009 UTILITY CAPITAL EXPENDITURES
FROM ACTUAL 2008 UTILITY CAPITAL EXPENDITURES

The 2009 Actual was $349.1 million, which is $16.9 million or 4.6% less than the 2008 Actual of $366.0 million. The capital expenditure decrease was primarily related to decreased requirements in customer related expenditures, storage plant and system improvements and upgrades. This was partially offset by increased requirements for general plant and increased spending on the Customer Information System (CIS). The major categories showing significant variances are explained below:

Item No.

1.1.4 Customer Related Distribution Plant – Decrease $10.8 Million
The decrease in customer related plant was driven by the completion of the Portlands Energy Power generation project ($10 million). A further $6.6 million of the decrease reflects the lower number of new customers added in 2009 (32,080) compared to 2008 (41,052). This was partially offset by increased expenditures for Northland Thorold Power and other power generation initiatives ($2.7M), and a higher allocation of indirect costs ($3.1M).

1.2.4 Improvement Mains – Decrease $15.6 Million
The decrease in improvement mains was primarily due to the completion of the Georgian Bay Reinforcement project in 2008 ($8.5M) and reduced allocation of indirect costs ($7.1M).

1.2.5 Service Relays – Increase $6.6 Million
The increase was primarily due the spending mix of the cast iron replacement program which is a combination of replacement mains and service relays. Relative to 2008, the service relay requirements were higher in 2009.

Witnesses: L. Au
D. Kelly

1.2.6 Regulator Refits – Increase $4.2 Million

The increase was due to more refit requirements relative to 2008. This activity is mandated by the government inspection meter exchange program ($3.7M). A portion of the activity is attributable to Safety and Integrity initiatives related to regulator replacement ($0.5M).

1.2.7 Measurement and Regulation – Decrease $4.2 Million

The decrease was primarily due to reduced improvement activity ($2.8M), less spending on the Fuel Cell Turbo Expander ($1.1M) and reduced allocation of indirect costs ($0.3M) relative to 2008.

1.2.8 Meters – Decrease $3.0 Million

The decrease was primarily due to less meter replacement requirements relative to 2008.

C. General and Other Plant – Increase $5.0 Million

The actual spending in this category increased relative to 2008 actual spending. Some 2009 general plant expenditures were advanced. Computer equipment increased $6.5M and Transportation and Heavy Work Equipment increased $0.4 million. The variance was partially offset by decreased requirements in Tools and Work Equipment ($1.3M) and Land Structures and Improvements ($0.5M).

D. Underground Storage Plant – Decrease $1.3 million

The decrease in storage plant expenditures reflects a decline in structures, compression equipment and measurement and regulation equipment partially offset by an increase in wells.

E. Customer Information System (CIS) – Increase $2.3 million

CIS was a multi-year project that commenced in 2007. CIS had a separate approval process with an approved spending of approximately $120M. At the end of 2009 the life to date spend was $127.5 million. The project variance was due to higher system integrator costs and higher interest during construction costs as the result of a delay in the implementation of the system and higher interest rates.

Witnesses: L. Au
D. Kelly

UTILITY OPERATING REVENUE
2010 HISTORICAL YEAR

Line No.		Col. 1 Utility Revenue ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Revenue ($Millions)
1.	Gas sales	1,942.2	45.8	1,988.0
2.	Transportation of gas	450.5	9.6	460.1
3.	Transmission, compression & storage	1.4	-	1.4
4.	Other operating revenue	40.5	-	40.5
5.	Other income	13.3	-	13.3
6.	Total operating revenue	2,447.9	55.4	2,503.3

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2010 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	45.8	Gas sales Adjustment to gas sales revenue required to reflect normal weather.
2.	9.6	Transportation of gas Adjustment to gas transportation revenue required to reflect normal weather.

Witnesses: K. Culbert
R. Small

UTILITY REVENUE
2010 HISTORICAL YEAR

Line No.		Col. 1 EGDI Ont. Corporate Revenue ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Revenue ($Millions)
1.	Residential	1,225.4	(0.2)	1,225.2
2.	Commercial	597.8	-	597.8
3.	Industrial	89.2	-	89.2
4.	Wholesale	30.0	-	30.0
5.	Gas sales	1,942.4	(0.2)	1,942.2
6.	Transportation of gas	450.5	-	450.5
7.	Transmission, compression & storage	1.4	-	1.4
8.	Service charges & DPAC	13.0	-	13.0
9.	Rent from NGV rentals	0.5	0.3	0.8
10.	Late payment penalties	13.1	-	13.1
11.	Transactional services	11.3	(3.3)	8.0
12.	Open bill revenue	7.4	(2.0)	5.4
13.	Dow Moore recovery	0.2	-	0.2
14.	Affiliate asset use revenue	0.1	(0.1)	-
15.	ABC T-service (net)	6.7	(6.7)	-
16.	Other operating revenue	52.3	(11.8)	40.5
17.	Income from investments	0.4	(0.4)	-
18.	Interest during construction	2.8	(2.8)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	-	-	-
21.	Property/asset use revenue 3rd party	1.3	(1.3)	-
22.	Interest and property rental	4.5	(4.5)	-
23.	Miscellaneous	28.6	(15.3)	13.3
24.	Dividend income	64.4	(64.4)	-
25.	Profit on sale of property	-	-	-
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	93.0	(79.7)	13.3
28.	Total revenue	2,544.1	(96.2)	2,447.9

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2010 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	(0.2)	Residential Gas Sales	
		Adjustment related to the updated tax saving sharing agreement (Exhibit C-1-4 and B-1-5).	
9.	0.3	Rent from NGV rentals	
		NGV revenue imputation to equate the program's overall return to the required regulated return.	
11.	(3.3)	Transactional services	
		To eliminate transactional services revenues above the base amount included in approved rates. Ratepayer amounts above the base have been transferred to the 2010 TSDA, and shareholder amounts are eliminated from utility returns.	
12.	(2.0)	Open bill revenue	
		To eliminate the shareholder portion of OBSDA and OBAVA write-of	0.2
		To eliminate the shareholder portion of net ex-franchise revenues	(0.3)
		To eliminate the Open Bill shareholder incentive	(1.9)
			(2.0)
14.	(0.1)	Affiliate asset use revenue	
		To reflect the elimination of asset use revenue in conjunction with the removal of affiliate use asset values from rate base and all related cost of service elements. (RP-2002-0133)	
15.	(6.7)	ABC T-Service (net)	
		To eliminate the net revenue from ABC T-Service considered to be non-utility. (RP-1999-0001)	

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2010 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
17.	(0.4)	Income from investments	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(2.8)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
21.	(1.3)	Property/asset use revenue 3rd party	
		To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)	
23.	(15.3)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(9.9)
		To eliminate the shareholders' incentive income recorded as a result of calculating the SSMVA amount.	(5.4)
			(15.3)
24.	(64.4)	Dividend income	
		To eliminate non-utility inter-company dividend income.	(1.7)
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	(62.7)
			(64.4)

Witnesses: K. Culbert
R. Small

COMPARISON OF GAS SALES AND TRANSPORTATION VOLUME BY RATE CLASS
2010 ACTUAL AND 2010 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2010 Actual	Col. 2 2010 Board Approved Budget	Col. 3 2010 Actual Over (Under) 2010 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 119.2	3 030.6	88.6
1.1.2	Rate 1 - T-Service	1 294.7	1 615.5	(320.8)
1.1	Total Rate 1	4 413.9	4 646.1	(232.2)
1.2.1	Rate 6 - Sales	1 959.3	1 990.4	(31.1)
1.2.2	Rate 6 - T-Service	2 382.7	2 445.3	(62.6)
1.2	Total Rate 6	4 342.0	4 435.7	(93.7)
1.3.1	Rate 9 - Sales	1.0	1.4	(0.4)
1.3.2	Rate 9 - T-Service	0.1	0.3	(0.2)
1.3	Total Rate 9	1.1	1.7	(0.6)
1.	Total General Service Sales & T-Service	8 757.0	9 083.5	(326.5)
Contract Sales				
2.1	Rate 100	4.8	0.0	4.8
2.2	Rate 110	69.1	43.9	25.2
2.3	Rate 115	(2.1)	4.4	(6.5)
2.4	Rate 135	5.6	5.9	(0.3)
2.5	Rate 145	22.0	25.2	(3.2)
2.6	Rate 170	37.8	79.7	(41.9)
2.7	Rate 200	169.6	156.1	13.5
2.	Total Contract Sales	306.8	315.2	(8.4)
Contract T-Service				
3.1	Rate 100	17.8	0.0	17.8
3.2	Rate 110	493.3	518.8	(25.5)
3.3	Rate 115	480.1	421.2	58.9
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	67.4	52.2	15.2
3.6	Rate 145	211.2	196.8	14.4
3.7	Rate 170	579.4	463.4	116.0
3.8	Rate 300	27.6	41.0	(13.4)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 876.8	1 693.4	183.4
4.	Total Contract Sales & T-Service	2 183.6	2 008.6	175.0
5.	Total	10 940.6	11 092.1	(151.5)

* There is no distribution volume for Rate 125 customers.

Witness: I. Chan

COMPARISON OF GAS SALES AND TRANSPORTATION VOLUME BY RATE CLASS 2010 ACTUAL AND 2010 BOARD APPROVED BUDGET (10^6m^3)

Item No.		Col. 1 2010 Actual	Col. 2 2010 Board Approved Budget	Col. 3 2010 Actual Over (Under) 2010 Budget (1-2)	Col. 4 2010* Adjustments	Col. 5 2010 Actual Over (Under) 2010 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	3 119.2	3 030.6	88.6	83.9	172.5
1.1.2	Rate 1 - T-Service	1 294.7	1 615.5	(320.8)	74.8	(246.0)
1.1	Total Rate 1	4 413.9	4 646.1	(232.2)	158.7	(73.5)
1.2.1	Rate 6 - Sales	1 959.3	1 990.4	(31.1)	48.6	17.5
1.2.2	Rate 6 - T-Service	2 382.7	2 445.3	(62.6)	70.2	7.6
1.2	Total Rate 6	4 342.0	4 435.7	(93.7)	118.8	25.1
1.3.1	Rate 9 - Sales	1.0	1.4	(0.4)	0.0	(0.4)
1.3.2	Rate 9 - T-Service	0.1	0.3	(0.2)	0.0	(0.2)
1.3	Total Rate 9	1.1	1.7	(0.6)	0.0	(0.6)
1.	Total General Service Sales & T-Service	8 757.0	9 083.5	(326.5)	277.5	(49.0)
Contract Sales						
2.1	Rate 100	4.8	0.0	4.8	0.0 **	4.8
2.2	Rate 110	69.1	43.9	25.2	0.1	25.3
2.3	Rate 115	(2.1)	4.4	(6.5)	0.0	(6.5)
2.4	Rate 135	5.6	5.9	(0.3)	0.0	(0.3)
2.5	Rate 145	22.0	25.2	(3.2)	0.6	(2.6)
2.6	Rate 170	37.8	79.7	(41.9)	0.3	(41.6)
2.7	Rate 200	169.6	156.1	13.5	6.0	19.5
2.	Total Contract Sales	306.8	315.2	(8.4)	7.0	(1.4)
Contract T-Service						
3.1	Rate 100	17.8	0.0	17.8	0.1	17.9
3.2	Rate 110	493.3	518.8	(25.5)	0.0 **	(25.5)
3.3	Rate 115	480.1	421.2	58.9	(0.1)	58.8
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	67.4	52.2	15.2	0.0	15.2
3.6	Rate 145	211.2	196.8	14.4	0.3	14.7
3.7	Rate 170	579.4	463.4	116.0	0.6	116.6
3.8	Rate 300	27.6	41.0	(13.4)	0.0	(13.4)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 876.8	1 693.4	183.4	0.9	184.3
4.	Total Contract Sales & T-Service	2 183.6	2 008.6	175.0	7.9	182.9
5.	Total	10 940.6	11 092.1	(151.5)	285.4	133.9

*Note: Weather normalization adjustments have been made to the 2010 Actual utilizing the 2010 Board Approved Budget Degree Days in order to place the two years on a comparable basis.

** Less than 50,000 m^3

Witness: I. Chan

The principal reasons for the variances contributing to the weather normalized increase of 133.9 10^6m^3 in the 2010 Actual over the 2010 Board Approved Budget are as follows:

1. The volumetric decrease of 73.5 10^6m^3 in Rate 1 was due to a lower average use per customer totaling 76.1 10^6m^3; paritially offset by a favourable customer variance of 2.6 10^6m^3;

2. The volumetric increase of 25.1 10^6m^3 in Rate 6 was due to net customer migration from Contract Sales and T-Service of 106.7 10^6m^3 and a higher average use per customer totaling 76.3 10^6m^3; partially offset by an unfavourable customer variance of 157.9 10^6m^3;

3. The volumetric decrease of 0.6 10^6m^3 in Rate 9 was due to a lower average use per station totaling 0.4 10^6m^3 and the loss of four stations of 0.2 10^6m^3;

4. The volumetric increase for Contract Sales and T-Service of 182.9 10^6m^3 was due to increases in the apartment sector of 21.7 10^6m^3, the commerical sector of 61.3 10^6m^3, the industrial sector of 80.4 10^6m^3 and Rate 200 of 19.5 10^6m^3. The increase was primarily attributable to lower gas prices than was budgeted.

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2010 HISTORICAL YEAR AND 2010 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2010 Actual	Col. 2 2010 Board Approved Budget	Col. 3 2010 Actual Over (Under) 2010 Budget (1-2)	Col. 4 2010* Adjustments	Col. 5 2010 Actual Over (Under) 2010 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	1 224.3	1 197.5	26.8	29.4	56.2
1.1.2	Rate 1 - T-Service	230.5	277.1	(46.6)	7.1	(39.5)
1.1	Total Rate 1	1 454.8	1 474.6	(19.8)	36.5	16.7
1.2.1	Rate 6 - Sales	648.2	659.2	(11.0)	16.6	5.6
1.2.2	Rate 6 - T-Service	173.4	182.7	(9.3)	4.6	(4.7)
1.2	Total Rate 6	821.6	841.9	(20.3)	21.2	0.9
1.3.1	Rate 9 - Sales	0.4	0.5	(0.2)	0.0	(0.2)
1.3.2	Rate 9 - T-Service	0.0 **	0.1	(0.0) **	0.0	(0.0)
1.3	Total Rate 9	0.4	0.6	(0.2)	0.0	(0.2)
1.	Total General Service Sales & T-Service	2 276.9	2 317.1	(40.3)	57.7	17.4
Contract Sales						
2.1	Rate 100	1.6	0.0	1.6	0.0 **	1.6
2.2	Rate 110	18.4	11.5	6.9	0.0 **	6.9
2.3	Rate 115	(0.1)	1.1	(1.2)	0.0	(1.2)
2.4	Rate 135	0.8	1.4	(0.7)	0.0	(0.7)
2.5	Rate 145	5.5	6.5	(1.0)	0.2	(0.8)
2.6	Rate 170	12.3	18.6	(6.3)	0.1	(6.2)
2.7	Rate 200	30.0	32.8	(2.8)	1.5	(1.3)
2.	Total Contract Sales	68.3	71.9	(3.6)	1.8	(1.8)
Contract T-Service						
3.1	Rate 100	1.2	0.0	1.2	0.0 **	1.2
3.2	Rate 110	15.6	14.5	1.1	0.0 **	1.1
3.3	Rate 115	6.5	6.3	0.2	0.0 **	0.2
3.4	Rate 125	7.7	7.4	0.3	0.0 ***	0.3
3.5	Rate 135	2.4	1.1	1.3	0.0	1.3
3.6	Rate 145	7.2	5.8	1.4	0.0 **	1.4
3.7	Rate 170	6.5	0.1	6.4	0.0 **	6.4
3.8	Rate 300	0.4	0.5	(0.1)	0.0	(0.1)
3.9	Rate 315	0.4	0.0	0.4	0.0	0.4
3.	Total Contract T-Service	47.8	35.8	12.1	0.0	12.1
4.	Total Contract Sales & T-Service	116.2	107.7	8.5	1.8	10.3
5.	Total	2 393.0	2 424.8	(31.8)	59.5	27.7

* Note: Weather normalization adjustments have been made to the 2010 Actuals utilizing the 2010 Board Approved Budget degree days in order to place the two years on a comparable basis. Please refer to Exhibit B, Tab 3, Schedule 2, Page 2, for the corresponding volumetric adjustments.

** Less than $50,000

*** There is no distribution volume for Rate 125 customers

Witness: I. Chan

1. Gas sales and transportation of gas revenues for the 2010 Test Year Budget were developed on the basis of EB-2009-0172 rates.

2. The principal reasons for the variances contributing to the decrease of $31.8 million in the 2010 Actual over the 2010 Budget are as follows:

3. <u>Gas Sales - Increase of $12.0 Million</u>

   The increase in gas sales revenue was primarily due to general service customer migration from transportation service to gas sales; partially offset by lower actual commodity charges than budgeted.

   Details on volumes are filed at Exhibit B, Tab 3, Schedule 2, pages 1 to 3.

4. <u>Transportation of Gas - Decrease of $43.8 Million</u>

   The decrease in T-Service revenue was mainly due to general service customer migration from transportation service to gas sales, partially offset by higher actual transportation charges than budgeted.

   Details on volumes are filed at Exhibit B, Tab 3, Schedule 2, pages 1 to 3.

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2010 ACTUAL

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	Col. 3 Revenues ($Millions)
General Service				
1.1.1	Rate 1 - Sales	1 260 809	3 119.2	1 224.3
1.1.2	Rate 1 - T-Service	511 694	1 294.7	230.5
1.1	Total Rate 1	1 772 503	4 413.9	1 454.8
1.2.1	Rate 6 - Sales	112 380	1 959.3	648.2
1.2.2	Rate 6 - T-Service	40 829	2 382.7	173.4
1.2	Total Rate 6	153 209	4 342.0	821.6
1.3.1	Rate 9 - Sales	22	1.0	0.4
1.3.2	Rate 9 - T-Service	1	0.1	0.0 **
1.3	Total Rate 9	23	1.1	0.4
1.	Total General Service Sales & T-Service	1 925 735	8 757.0	2 276.9
Contract Sales				
2.1	Rate 100	7	4.8	1.6
2.2	Rate 110	37	69.1	18.4
2.3	Rate 115	0	(2.1)	(0.1)
2.4	Rate 135	6	5.6	0.8
2.5	Rate 145	14	22.0	5.5
2.6	Rate 170	6	37.8	12.3
2.7	Rate 200	1	169.6	30.0
2.	Total Contract Sales	71	306.8	68.3
Contract T-Service				
3.1	Rate 100	28	17.8	1.2
3.2	Rate 110	176	493.3	15.6
3.3	Rate 115	32	480.1	6.5
3.4	Rate 125	4	0.0 *	7.7
3.5	Rate 135	30	67.4	2.4
3.6	Rate 145	174	211.2	7.2
3.7	Rate 170	35	579.4	6.5
3.8	Rate 300	9	27.6	0.4
3.9	Rate 315	0	0.0	0.4
3.	Total Contract T-Service	488	1 876.8	47.8
4.	Total Contract Sales & T-Service	559	2 183.6	116.2
5.	Total	1 926 294	10 940.6	2 393.0

* There is no distribution volume for Rate 125 customers.

** Less than $50,000.

Witness: I. Chan

DETAILS OF OTHER REVENUE AND OTHER INCOME
2010 HISTORICAL AND 2009 HISTORICAL

Item No.		Col. 1 2010 Historical ($Millions)	Col. 2 2009 Historical ($Millions)	Col. 3 2010 Historical Over/(Under) 2009 Historical ($Millions)
1.1	Service Charges & DPAC	13.0	12.7	0.3
1.2	Rental Revenue - NGV Program	0.8	0.6	0.2
1.3	Late Payment Penalties	13.1	14.0	(0.9)
1.4	Dow Moore Recovery	0.2	0.2	-
1.5	Transactional Services (net)	8.0	8.0	-
1.6	Ontario Power Authority Program Revenue	11.7	5.9	5.8
1.7	Miscellaneous	1.6	1.6	-
1.8	Open Bill Revenue	5.4	5.4	-
1.9	Total Other Revenue	53.8	48.4	5.4

Witness: R. Lei

DETAILS OF OTHER REVENUE
2009 HISTORICAL YEAR AND 2008 HISTORICAL YEAR

Item No.		Col. 1 2009 Historical Year ($Millions)	Col. 2 2008 Historical Year ($Millions)	Col. 3 2009 Historical Over/(Under) 2008 Historical ($Millions)
1.1	Service Charges & DPAC	12.7	12.4	0.3
1.2	Rental Revenue - NGV Program	0.6	0.9	(0.3)
1.3	Late Payment Penalties	14.0	12.0	2.0
1.4	Dow Moore Recovery	0.2	0.2	-
1.5	Transactional Services (net)	8.0	8.0	-
1.6	Ontario Power Authority (OPA) New Construction Program Revenue	5.9	3.6	2.3
1.7	Miscellaneous	1.6	0.7	0.9
1.8	Open Bill Revenue	5.4	5.4	-
1.9	Total Other Revenue	48.4	43.2	5.2

Witness: R. Lei

COST OF SERVICE
2010 HISTORICAL YEAR

Line No.		Col. 1 Utility Costs and Expenses ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Adjusted Utility Costs and Expenses ($Millions)
1.	Gas costs	1,412.7	38.0	1,450.7
2.	Operation and maintenance	346.7	-	346.7
3.	Depreciation and amortization expense	266.9	-	266.9
4.	Fixed financing costs	4.8	-	4.8
5.	Debt redemption premium amortization	0.3	-	0.3
6.	Company share of IR agreement tax savings	16.0	-	16.0
7.	Municipal and other taxes	40.7	-	40.7
8.	Operating costs	2,088.1	38.0	2,126.1
9.	Income tax expense			71.2
10.	Cost of service			2,197.3

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2010 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	38.0	Gas Costs Adjustment required to gas costs to reflect normal weather.

Witnesses: K. Culbert
R. Small

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2010 HISTORICAL YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	377.2	377.2	
	Add			
2.	Depreciation and amortization	266.9	266.9	
3.	Other non-deductible items	1.5	1.5	
4.	Total Add Back	268.4	268.4	
5.	Sub-total	645.6	645.6	
	Deduct			
6.	Capital cost allowance	219.7	219.7	
7.	Items capitalized for regulatory purposes	42.7	42.7	
8.	Deduction for "grossed up" Part VI.1 tax	2.5	2.5	
9.	Amortization of share/debenture issue expense	2.7	2.7	
10.	Amortization of cumulative eligible capital	0.4	0.4	
11.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
12.	Total Deduction	268.1	268.1	
13.	Taxable income	377.5	377.5	
14.	Income tax rates	18.00%	13.00%	
15.	Provision	68.0	49.1	117.1
16.	Part VI.1 tax			0.8
17.	Total taxes excluding interest shield			117.9
	Tax shield on interest expense			
18.	Rate base	3,837.7		
19.	Return component of debt	3.93%		
20.	Interest expense	150.9		
21.	Combined tax rate	31.000%		
22.	Income tax credit			(46.7)
23.	Total utility income taxes			71.2

Witnesses: K. Culbert
R. Small

COST OF SERVICE
2010 HISTORICAL YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses	Col. 2 Adjustment	Col. 3 Utility Costs and Expenses
		($Millions)	($Millions)	($Millions)
1.	Gas costs	1,412.7	-	1,412.7
2.	Operation and maintenance	381.4	(34.7)	346.7
3.	Depreciation	265.8	(0.3)	265.5
4.	Amortization	1.4	-	1.4
5.	Depreciation and amortization	267.2	(0.3)	266.9
6.	Fixed financing costs	4.8	-	4.8
7.	Debt redemption premium amortization	0.3	-	0.3
8.	Company share of IR agreement tax savings	-	16.0	16.0
9.	Municipal and other taxes	37.8	(0.2)	37.6
10.	Capital taxes	4.7	(1.6)	3.1
11.	Municipal and other taxes	42.5	(1.8)	40.7
12.	Interest on long-term debt	149.4	(149.4)	-
13.	Amortization of preference share issue costs and debt discount and expense	2.4	(2.4)	-
14.	Interest and financing amortization	151.8	(151.8)	-
15.	Interest on short-term debt	4.2	(4.2)	-
16.	Interest due affiliates	26.8	(26.8)	-
17.	Other interest expense	31.0	(31.0)	-
18.	Total operating costs	2,291.7	(203.6)	2,088.1
19.	Current taxes	58.1	(58.1)	-
20.	Deferred taxes	1.2	(1.2)	-
21.	Income tax expense	59.3	(59.3)	-
22.	Cost of service	2,351.0	(262.9)	2,088.1

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2010 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(34.7)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	0.5
		To eliminate donations (EBRO 490).	(1.6)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.8)
		To eliminate Corporate Cost allocations above RCAM amount.	(12.4)
		To remove the expensing of the 2009 OHCVA from utility O&M.	(0.5)
		To eliminate ESM amounts contained in the Corporate financials.	(18.9)
			(34.7)
3.	(0.3)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.2)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.1)
			(0.3)
8.	16.0	Company share of IR agreement tax savings	
		To reflect the impact of the shareholder portion of agreed tax savings on utility income.	
9.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	
10.	(1.6)	Capital taxes	
		Adjustment to capital taxes needed to convert the capital tax calculation to a utility "stand-alone" basis.	

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2010 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
12.	(149.4)	Interest on long-term debt Expense of capital.
13.	(2.4)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
15.	(4.2)	Interest on short-term debt Expense of capital.
16.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
19.	(58.1)	Income taxes - current Income tax expense related to corporate earnings.
20.	(1.2)	Income taxes - deferred Income tax expense related to corporate earnings.

PROVINCIAL CAPITAL TAX - CALCULATED ON YEAR END BALANCES
2010 HISTORICAL YEAR

Line No.		Col. 1 Provincial Capital Tax ($Millions)
1.	Property, Plant, and Equipment - year end NBV	3,670.4
2.	Working capital / not in service taxable work in progress	438.6
3.	Other unclaimed tax treatments	6.3
4.	Taxable Capital	4,115.3
5.	Less exemption	(7.5)
6.	Adjusted taxable capital	4,107.8
7.	Capital tax rate	0.075%
8.	Provincial Capital Tax	3.1

Witnesses: K. Culbert
R. Small

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2010 HISTORICAL YEAR

Capital Cost Allowance - Federal

Col 1 Class No.	Col 2 UCC AT Beginning of year	Col 3 Cost of Additions	Col 4 Lessor of Costs or Proceeds	Col 5 Less 50 % of net [Cols 3 - 4]	Col 6 Rate %	Col 7 CCA F2010	Col 8 UCC Carry Forward
1	2,105,195,106	0	150,000	75,000	4.00%	(84,210,804)	2,021,134,302
51	625,752,522	222,972,040	0	111,486,020	6.00%	(44,234,313)	804,490,250
2	147,200,684	0	0	0	6.00%	(8,832,041)	138,368,643
6	17,937	0	0	0	10.00%	(1,794)	16,143
8	8,321,292	1,414,695	(845,000)	284,848	20.00%	(1,721,228)	7,169,759
10	26,541,852	23,048,836	(256,667)	11,396,085	30.00%	(11,381,381)	37,952,640
12	8,035,581	19,618,500	0	9,809,250	100.00%	(17,844,831)	9,809,250
12	90,129,495	0	0	0	33.33%	(30,043,165)	60,086,330
17	41,588	0	0	0	8.00%	(3,327)	38,261
38	4,459,950	492,000	(50,000)	221,000	30.00%	(1,404,285)	3,497,665
41	22,829,899	1,482,337	54,000	768,169	25.00%	(5,899,517)	18,466,719
13	1,051,436	135,000	0	67,500		(249,000)	937,436
3	276,098	0	0	0	5.00%	(13,805)	262,293
45	2,943,635	0	0	0	45.00%	(1,324,636)	1,618,999
50	8,627,851	0	0	0	55.00%	(4,745,318)	3,882,533
52	0	8,000,000	0	0	100.00%	(8,000,000)	0
Total	3,051,424,926	277,163,408	(947,667)	134,107,871		(219,909,444)	3,107,731,223

Non-utility and shared asset eliminations	221,184
Utility Federal CCA	(219,688,260)

Capital Cost Allowance - Ontario

Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2010	UCC Carry Forward
1	2,105,195,106	0	150,000	75,000	4.00%	(84,210,804)	2,021,134,302
51	625,752,522	222,972,040	0	111,486,020	6.00%	(44,234,313)	804,490,250
2	147,200,684	0	0	0	6.00%	(8,832,041)	138,368,643
6	17,937	0	0	0	10.00%	(1,794)	16,143
8	8,321,292	1,414,695	(845,000)	284,848	20.00%	(1,721,228)	7,169,759
10	26,541,852	23,048,836	(256,667)	11,396,085	30.00%	(11,381,381)	37,952,640
12	8,035,581	19,618,500	0	9,809,250	100.00%	(17,844,831)	9,809,250
12	90,129,495	0	0	0	33.33%	(30,043,165)	60,086,330
17	41,588	0	0	0	8.00%	(3,327)	38,261
38	4,459,950	492,000	(50,000)	221,000	30.00%	(1,404,285)	3,497,665
41	22,829,899	1,482,337	54,000	768,169	25.00%	(5,899,517)	18,466,719
13	1,051,436	135,000	0	67,500		(249,000)	937,436
3	276,098	0	0	0	5.00%	(13,805)	262,293
45	2,943,635	0	0	0	45.00%	(1,324,636)	1,618,999
50	8,627,851	0	0	0	55.00%	(4,745,318)	3,882,533
52	0	8,000,000	0	0	100.00%	(8,000,000)	-
Total	3,051,424,926	277,163,408	(947,667)	134,107,871		(219,909,444)	3,107,731,223

Non-utility and shared asset eliminations	221,184
Utility Provincial CCA and UCC	(219,688,260)

Witnesses: K. Culbert
R. Small

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAINTENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars ($ 000's)	Col. 1 Actual 2010	Col. 2 Actual 2009	Col. 3 Actual 2008	Col. 4 2010 Actual Over/(Under) 2009 Actual	Col. 5 Board Approved 2007 Utility O&M
1.	Finance	$ 6,016	$ 5,981	$ 5,843	$ 35	$ 8,380
2.	Risk Management	2,141	2,865	1,695	(724)	1,986
3.	Customer Care Service Charges	68,742	82,042	84,583	(13,300)	83,493
4.	Customer Care Internal Costs	9,222	7,868	9,679	1,354	7,302
5.	Provision for Uncollectibles	11,500	17,855	16,660	(6,355)	15,105
6.	Energy Supply, Storage, Regulatory	20,534	19,016	19,471	1,518	21,904
7.	Legal and Corporate Services	1,407	1,170	1,147	237	1,207
8.	Operations	50,060	44,199	43,308	5,861	44,728
9.	Information Technology	30,398	22,695	21,247	7,703	21,790
10.	Business Development & Customer Strategy (excluding DSM)	18,567	14,255	13,364	4,312	19,118
11.	Human Resources (excluding benefits)	15,127	14,568	13,272	559	13,059
12.	Benefits	27,335	26,241	24,597	1,094	21,405
13.	Engineering	27,891	24,949	22,851	2,942	20,982
14.	Public and Government Affairs	8,137	5,764	5,484	2,373	5,760
15.	Non Departmental Expenses	24,267	30,899	29,497	(6,632)	17,305
16.	Corporate Allocations (including direct costs)	36,692	34,266	32,166	2,426	18,100
17.	Total	358,036	354,633	344,866	3,403	321,624
18.	Capitalization (A&G)	(24,330)	(23,902)	(21,643)	(428)	(17,424)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	333,706	330,731	323,223	2,975	304,200
20.	Demand Side Management Programs (DSM)	25,468	24,255	23,100	1,213	22,000
21.	Total Net Utility Operating and Maintenance Expense	$ 359,174	$ 354,986	$ 346,323	$ 4,188	$ 326,200
22.	Regulatory Adjustments					
23.	To eliminate Corporate Cost Allocations above RCAM	(12,428)	(13,100)	(13,066)	672	
24.	To eliminate CIS fees above Customer Care settlement agreement	-	(4,900)	(9,811)	4,900	
25.	Total Adjustments	(12,428)	(18,000)	(22,877)	5,572	
26.	Utility O&M	$ 346,746	$ 336,986	$ 323,446	$ 9,760	

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.

Witnesses: R. Lei
A. Patel

EXPLANATION OF MAJOR CHANGES
ACTUAL 2010 O&M EXPENSES COMPARED TO ACTUAL 2009 O&M EXPENSES

The 2010 Actual Utility O&M was $346.7 million, which was $9.7 million higher than the 2009 Actual Utility O&M of $337.0 million. The increase was primarily driven by higher hosting and support costs for the new CIS, operational outside service costs, conservation service costs, and corporate cost allocations. The increased O&M costs were partially offset by lower (old) CIS hosting and support fees, and provision for uncollectibles.

Line No:

3. Customer Care Service Charges decreased $13.3 million due to the elimination of (old) CIS hosting and support fees from Customer Care, with (new) CIS hosting and support costs now residing in Information Technology.

4. Customer Care Internal Costs increased $1.4 million due to higher consulting costs.

5. Provision for Uncollectibles decreased $6.4 million due to the implementation of SAP which resulted in enhanced customer information.

6. Energy Supply, Storage, and Regulatory increased $1.5 million primarily due to higher well logging and compressor repair costs, and higher employee related costs.

8. Operations increased $5.9 million due to higher outside service costs, and higher employee costs.

9. Information Technology increased $7.7 million due to a full year of hosting and support fees for the new CIS versus partial 2009 year fees, and higher hardware/software maintenance costs.

Witnesses: R. Lei
A. Patel

10. Business Development & Customer Strategy increased $4.3 million due to higher conservation service costs.

12. Benefits increased $1.1 million due to higher pension plan expenses.

13. Engineering costs increased $3.2 million due to increased requirements for the Technical Training department, and increased Employee Health and Safety costs.

14. Public and Government Affairs increased $2.4 million primarily due to the transfer of the Ombudsman Office from Customer Care and incremental costs incurred, and from a customer relationship study conducted in 2010.

15. Non Departmental Expenses decreased $6.6 million in relation to decreased variable compensation related expenses.

16. Corporate Allocations increased $2.9 million primarily due to higher compensation related costs.

20. Demand Side Management increased $1.2 million due to the higher level of Board Approved program spending.

Witnesses: R. Lei
A. Patel

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2010 HISTORICAL YEAR

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component	Col. 5 (col 1x col 3) Interest & pref share Expense
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	2,190.7	57.08	6.77	3.864	148.3
2.	Short-Term Debt	165.4	4.31	1.61	0.069	2.6
3.		2,356.1	61.39		3.933	
4.	Preference Shares	100.0	2.61	2.08	0.054	2.1
						153.0
5.	Common Equity	1,381.6	36.00	9.37	3.373	
6.		3,837.7	100.00		7.360	
7.	Rate Base (Ex. B-2-1)	($Millions)			3,837.70	
8.	Utility Income (Ex. B-5-2)	($Millions)			306.00	
9.	Indicated Rate of Return				7.974	
10.	Sufficiency in Rate of Return				0.614	
11.	Net Sufficiency	($Millions)			23.56	
12.	Gross Sufficiency	($Millions)			34.15	
13.	Revenue at Existing Rates	($Millions)			2,449.60	
14.	Revenue Requirement	($Millions)			2,415.45	
15.	Gross Revenue Sufficiency	($Millions)			34.15	
	Common Equity					
16.	Allowed Rate of Return				9.370	
17.	Earnings on Common Equity				11.08	
18.	Sufficiency in Common Equity Return				1.71	

Witnesses: K. Culbert
R. Small

UTILITY INCOME
2010 HISTORICAL YEAR

Line No.		Col. 1 Utility Income ($Millions)
1.	Gas sales	1,988.0
2.	Transportation of gas	460.1
3.	Transmission, compression and storage revenue	1.4
4.	Other operating revenue	40.5
5.	Interest and property rental	-
6.	Other income	13.3
7.	Total operating revenue (Ex. B-3-1-pg.1)	2,503.3
8.	Gas costs	1,450.7
9.	Operation and maintenance	346.7
10.	Depreciation and amortization expense	266.9
11.	Fixed financing costs	4.8
12.	Debt redemption premium amortization	0.3
13.	Company share of IR agreement tax savings	16.0
14.	Municipal and other taxes	40.7
15.	Interest and financing amortization expense	-
16.	Other interest expense	-
17.	Cost of service (Ex. B-4-1-pg.1)	2,126.1
18.	Utility income before income taxes	377.2
19.	Income tax expense (Ex. B-4-1-pg.3)	71.2
20.	Utility income	306.0

Witnesses: K. Culbert
R. Small

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2010 HISTORICAL YEAR

Line No.		Col. 1 Average of Monthly Averages ($Millions)	Col. 2	Col. 3 Carrying Cost ($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	2,211.3		149.8
2.	Unamortized Finance Costs	(20.6)		-
3.	(Profit)/Loss on Redemption	-		-
4.		2,190.7		149.8
5.	Calculated Cost Rate		6.77%	
	Short-Term Debt			
6.	Calculated Cost Rate		1.61%	
	Preference Shares			
7.	Preference Share Summary	100.0		2.1
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		2.1
11.	Calculated Cost Rate		2.08%	
	Common Equity			
12.	Board Approved Formula ROE		8.37%	
13.	100 Basis Point Allowance Before Earnings Sharing		1.00%	
14.	Total Allowed ROE for ESM Purposes		9.37%	

Witnesses: K. Culbert
R. Small

DEFERRAL & VARIANCE ACCOUNTS
REQUESTED FOR CLEARANCE JULY 1, 2011

1. The deferral and variance accounts EGD is requesting clearance of at July 1, 2011 are shown at page 2 of this schedule. The balances requested for clearance total approximately ($3.1) million, which is the combination of principal and interest amounts shown in Columns 3 and 4.

2. As shown in the footnotes or evidence referenced in the footnotes on page 2, EGD has provided some additional explanation information for selected accounts. The remaining accounts have either been approved in another proceeding, or have a previously established process which has been followed in determining account balances.

3. The interest calculated on the principal balances has been updated to include the use of the Board's January 1, 2011 prescribed interest rates for deferral and variance accounts. The eventual interest amounts to be cleared will be calculated using any updated Board prescribed quarterly interest rates that become effective before the approved date of clearance.

Witnesses: K. Culbert
R. Small

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

			Col. 1	Col. 2	Col. 3	Col. 4
			Actual at February 28, 2011		Forecast for clearance at July 1, 2011	
Line No.	Account Description	Account Acronym	Principal	Interest	Principal	Interest
			($000's)	($000's)	($000's)	($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2009 DSMVA	1,165.1	7.2	1,165.1	12.8
2.	Lost Revenue Adjustment Mechanism	2009 LRAM	(45.7)	(0.1)	(45.7)	(0.5)
3.	Shared Savings Mechanism V/A	2009 SSMVA	5,364.2	13.1	5,364.2	39.5
4.	Class Action Suit D/A	2011 CASDA	9,419.1	806.4	4,709.5	463.8 [1]
5.	Deferred Rebate Account	2010 DRA	(2,387.1)	12.4	(2,387.1)	0.8
6.	Gas Distribution Access Rule Costs D/A	2010 GDARCDA	132.7	0.9	2,904.4	- [2]
7.	Ontario Hearing Costs V/A	2010 OHCVA	92.1	0.2	92.1	0.6 [3]
8.	Unbundled Rate Implementation Cost D/A	2010 URICDA	144.1	0.6	144.1	1.4
9.	Open Bill Service D/A	2011 OBSDA	336.2	14.2	87.7	7.9 [4]
10.	Open Bill Access V/A	2011 OBAVA	304.5	7.3	79.4	4.4 [4]
11.	Municipal Permit Fees D/A	2010 MPFDA	901.6	-	306.3	- [2]
12.	Average Use True-Up V/A	2010 AUTUVA	(2,145.2)	(5.3)	(2,145.2)	(15.7) [5]
13.	Tax Rate and Rule Change V/A	2010 TRRCVA	704.0	1.7	516.1	5.3 [6]
14.	Earnings Sharing Mechanism D/A	2010 ESMDA	(18,500.0)	(45.3)	(17,100.0)	(136.1) [7]
15.	IFRS Transition Costs D/A	2010 IFRSTCDA	2,080.6	15.2	2,080.6	25.2
16.	Ex-Franchise Third Party Billing Services D/A	2010 EFTPBSDA	(251.9)	(0.6)	(251.9)	(1.8)
17.	Total non commodity related accounts		(2,685.7)	827.9	(4,480.4)	407.6
	Commodity Related Accounts					
18.	Transactional Services D/A	2010 TSDA	(7,264.5)	(28.7)	(7,264.5)	(64.3)
19.	Unaccounted for Gas V/A	2010 UAFVA	8,729.4	21.4	8,729.4	64.2
20.	Storage and Transportation D/A	2010 S&TDA	(531.8)	(1.7)	(531.8)	(4.5)
21.	Total commodity related accounts		933.1	(9.0)	933.1	(4.6)
22.	Total Deferral and Variance Accounts		(1,752.6)	818.9	(3,547.3)	403.0

Notes:

1. As approved in EB-2007-0731, the CASDA is to be cleared over 5 years (2008 - 2012). The 2008 installment was cleared in July and August 2008, the 2009 installment was cleared in April and May 2010, and the 2010 installment was cleared in January 2011. The Company is now requesting clearance of the 2011, or fourth installment, in this proceeding.

2. The forecast 2010 GDARCDA and 2010 MPFDA amounts for clearance are the result of revenue requirement calculations (found in evidence at Ex.C-1-2 and C-1-3).

3. The OHCVA calculation is found in evidence at Ex.C-1-6.

4. The forecast OBSDA and OBAVA balances are in accordance with the EB-2009-0043 approved Settlement Agreement.

5. The AUTUVA explanation is found in evidence at Ex.C-1-5.

6. The TRRCVA explanation is found in evidence at Ex.C-1-4.

7. The ESMDA explanation is found in evidence at Ex.B-1-1 and B-1-2.

Witnesses: K. Culbert
R. Small

GAS DISTRIBUTION ACCESS RULE COSTS DEFERRAL ACCOUNT

1. In the EB-2009-0172 Rate Order, the Board approved a 2010 Gas Distribution Access Rule Costs Deferral Account “GDARCDA” for the costs associated with the Company maintaining compliance with the Board’s Gas Distribution Access Rule directives.

2. EGD recorded both capital and operating costs incurred in 2010 within this deferral account.

3. In the EB-2007-0615 Final Rate Order, EB-2009-0055 Decision, and the EB-2010-0042 Decision, the Board approved clearance of the 2007, 2008, and 2009 GDAR compliance costs indicated using revenue requirement calculations to customers as one time rate rider adjustments. The result is that the Company’s distribution rates do not contain the ongoing impacts of GDAR compliance spending, and therefore, associated rate rider adjustments need to be established and cleared annually. As a result, the 2011 revenue requirement of the cumulative impact of the 2007, 2008, 2009, and 2010 Board Approved deferral account costs requires clearance through a rate rider adjustment. The Company is once again not seeking to recover the total amount of capital and/or O&M expended, as is the case for the majority of deferral accounts, but is proposing to recover on a one time basis the 2011 annual revenue requirement, determined through a revenue requirement / cost of service type of calculation, for the 2007 through 2010 cumulative expenditures. This revenue requirement treatment is consistent with the EB-2007-0615, EB-2009-0055, and EB-2010-0042 Board Decisions. In its EB-2006-0034 Decision, the Board accepted the disposition of the 2005 & 2006 GDAR deferral accounts whereby

the Company capitalized the related amounts into rate base and effectively recovered those accounts in a cost of service revenue requirement manner.

4. Within this revenue requirement calculation, the typical items recovered in a cost of service revenue requirement such as depreciation, total return on rate base including interest, equity and taxes, and other operating costs are being requested for recovery. The Company has used the 2007 Board Approved capital structure as a base within the revenue requirement calculation as it is the underlying capital structure in base rates which are used in EGD's 2008-2012 Incentive Regulation approved rates mechanism. This is consistent with the 2007, 2008, and 2009 Approved GDARCDA revenue requirement determinations.

5. The Company is proposing to recover $2.9 million as a one time billing adjustment in July, 2011 as shown in the proposed one time clearance balances at Exhibit C, Tab 1, Schedule 1, page 2, Columns 3 and 4. The determination of the 2011 annual revenue requirement associated with the combined 2007, 2008, 2009 and 2010 GDAR deferral account costs is shown on pages 3 through 7 of this schedule.

ONTARIO UTILITY CAPITAL STRUCTURE
2007, 2008, 2009 & 2010 GDARCDA IMPACTS

2007 Approved Capital Structure

Line No.		Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component
		%	%	%
1.	Long-term debt	59.65	7.31	4.36
2.	Short-term debt	1.68	4.12	0.07
3.		61.33		4.43
4.	Preference shares	2.67	5.00	0.13
5.	Common equity	36.00	8.39	3.02
6.		100.00		7.58

	($ 000's)	2008	2009	2010	2011
7.	Ontario Utility Income	(73.7)	(78.5)	(1,491.0)	(1,655.1)
8.	Rate base	6,273.7	5,455.9	4,251.9	2,640.3
9.	Indicated rate of return	(1.17)%	(1.44)%	(35.07)%	(62.69)%
10.	(Def.) / suff. in rate of return	(8.75)%	(9.02)%	(42.65)%	(70.27)%
11.	Net (def.) / suff.	(548.9)	(492.1)	(1,813.4)	(1,855.3)
12.	Gross (def.) / suff.	(859.3)	(770.4)	(2,838.8)	(2,904.4)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY RATE BASE
2007, 2008, 2009 & 2010 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011
	Property, plant, and equipment				
1.	Cost or redetermined value	7,004.5	7,676.4	8,060.5	8,060.5
2.	Accumulated depreciation	(730.8)	(2,220.5)	(3,808.6)	(5,420.2)
3.		6,273.7	5,455.9	4,251.9	2,640.3
	Allowance for working capital				
4.	Accounts receivable merchandise finance plan	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-
6.	Materials and supplies	-	-	-	-
7.	Mortgages receivable	-	-	-	-
8.	Customer security deposits	-	-	-	-
9.	Prepaid expenses	-	-	-	-
10.	Gas in storage	-	-	-	-
11.	Working cash allowance	-	-	-	-
12.		-	-	-	-
13.	Ontario utility rate base	6,273.7	5,455.9	4,251.9	2,640.3

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY INCOME
2007, 2008, 2009 & 2010 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011
	Revenue				
1.	Gas sales	-	-	-	-
2.	Transportation of gas	-	-	-	-
3.	Transmission and compression	-	-	-	-
4.	Other operating revenue	-	-	-	-
5.	Other income	-	-	-	-
6.	Total revenue	-	-	-	-
	Costs and expenses				
7.	Gas costs	-	-	-	-
8.	Operation and Maintenance	40.4	124.8	130.2	134.3
9.	Depreciation and amortization	1,461.6	1,541.2	1,611.6	1,611.6
10.	Municipal and other taxes	10.4	1.1	-	-
11.	Total costs and expenses	1,512.4	1,667.1	1,741.8	1,745.9
12.	Utility income before inc. taxes	(1,512.4)	(1,667.1)	(1,741.8)	(1,745.9)
	Income taxes				
13.	Excluding interest shield	(1,338.3)	(1,501.3)	(182.7)	(48.5)
14.	Tax shield on interest expense	(100.4)	(87.3)	(68.1)	(42.3)
15.	Total income taxes	(1,438.7)	(1,588.6)	(250.8)	(90.8)
16.	Ontario utility net income	(73.7)	(78.5)	(1,491.0)	(1,655.1)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2007, 2008, 2009 & 2010 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011
1.	Utility income before income taxes	(1,512.4)	(1,667.1)	(1,741.8)	(1,745.9)
	Add Backs				
2.	Depreciation and amortization	1,461.6	1,541.2	1,611.6	1,611.6
3.	Large corporation tax	-	-	-	-
4.	Other non-deductible items	-	-	-	-
5.	Any other add back(s)	-	-	-	-
6.	Total added back	1,461.6	1,541.2	1,611.6	1,611.6
7.	Sub total - pre-tax income plus add backs	(50.8)	(125.9)	(130.2)	(134.3)
	Deductions				
8.	Capital cost allowance - Federal	3,654.5	4,030.3	375.7	-
9.	Capital cost allowance - Provincial	3,654.5	4,030.3	375.7	-
10.	Items capitalized for regulatory purposes	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-
15.	Any other deduction(s)	-	-	-	-
16.	Total Deductions - Federal	3,654.5	4,030.3	375.7	-
17.	Total Deductions - Provincial	3,654.5	4,030.3	375.7	-
18.	Taxable income - Federal	(3,705.3)	(4,156.2)	(505.9)	(134.3)
19.	Taxable income - Provincial	(3,705.3)	(4,156.2)	(505.9)	(134.3)
20.	Income tax provision - Federal	(819.6)	(919.4)	(111.9)	(29.7)
21.	Income tax provision - Provincial	(518.7)	(581.9)	(70.8)	(18.8)
22.	Income tax provision - combined	(1,338.3)	(1,501.3)	(182.7)	(48.5)
23.	Part V1.1 tax	-	-	-	-
24.	Investment tax credit	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(1,338.3)	(1,501.3)	(182.7)	(48.5)
	Tax shield on interest expense				
26.	Rate base as adjusted	6,273.7	5,455.9	4,251.9	2,640.3
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	277.9	241.7	188.4	117.0
29.	Combined tax rate	36.120%	36.120%	36.120%	36.120%
30.	Income tax credit	(100.4)	(87.3)	(68.1)	(42.3)
31.	Total income taxes	(1,438.7)	(1,588.6)	(250.8)	(90.8)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY REVENUE REQUIREMENT
2007, 2008, 2009 & 2010 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011
	Cost of capital				
1.	Rate base	6,273.7	5,455.9	4,251.9	2,640.3
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	475.5	413.6	322.3	200.1
	Cost of service				
4.	Gas costs	-	-	-	-
5.	Operation and Maintenance	40.4	124.8	130.2	134.3
6.	Depreciation and amortization	1,461.6	1,541.2	1,611.6	1,611.6
7.	Municipal and other taxes	10.4	1.1	-	-
8.	Cost of service	1,512.4	1,667.1	1,741.8	1,745.9
	Misc. & Non-Op. Rev				
9.	Other operating revenue	-	-	-	-
10.	Other income	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-
	Income taxes on earnings				
12.	Excluding tax shield	(1,338.3)	(1,501.3)	(182.7)	(48.5)
13.	Tax shield provided by interest expense	(100.4)	(87.3)	(68.1)	(42.3)
14.	Income taxes on earnings	(1,438.7)	(1,588.6)	(250.8)	(90.8)
	Taxes on (def) / suff.				
15.	Gross (def.) / suff.	(859.3)	(770.4)	(2,838.8)	(2,904.4)
16.	Net (def.) / suff.	(548.9)	(492.1)	(1,813.4)	(1,855.3)
17.	Taxes on (def.) / suff.	310.4	278.3	1,025.4	1,049.1
18.	Revenue requirement	859.6	770.4	2,838.7	2,904.3
	Revenue at existing Rates				
19.	Gas sales	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.3	0.3	0.0	0.0
23.	Revenue at existing rates	0.3	0.3	0.0	0.0
24.	Gross revenue (def.) / suff.	(859.3)	(770.1)	(2,838.7)	(2,904.3)

Witnesses: K. Culbert
R. Small

MUNICIPAL PERMIT FEES DEFERRAL ACCOUNT

1. Within the EB-2010-0042 Rate Order, the Board approved the 2010 Municipal Permit Fees Deferral Account ("MPFDA") for fees imposed by Municipal governments for activities, such as road cuts, incurred in association with the Company's construction and maintenance operations. These are new charges, not included in base 2007 rates, resulting from changes to Ontario regulations made under the Municipal Act, 2001.

2. All amounts in relation to the 2010 deferral account are capital expenditure related (as were amounts related to the Boards approval of previous 2008 and 2009 accounts).

3. In the EB-2009-0055 and EB-2010-0042 Decisions, the Board approved clearance of the 2008 and 2009 MPFDA costs through a revenue requirement calculation, to be cleared to customers as a one time rate rider adjustment. As a result, the Company's distribution rates do not contain the ongoing impact of the 2008 and 2009 MPFDA spending. Therefore associated rate rider adjustments need to be established and cleared annually. As a result, the cumulative 2011 revenue requirement impact of the 2008, 2009 and 2010 Board Approved deferral account costs requires clearance through a rate rider adjustment. The Company is once again not seeking to recover the total amount of cash expended, as is the case for the majority of deferral accounts, but is proposing to recover on a one time basis the 2011 annual revenue requirement, determined through a revenue requirement / cost of service type of calculation, for the 2008, 2009 and 2010 cumulative expenditures. This revenue requirement treatment is consistent with past Board Decisions regarding the clearance of the 2008 and 2009 MPFDA's, and multiple decisions regarding the clearance of GDARCDA

amounts. The treatment/clearance of MPFDA costs in the same manner as GDARCDA costs is appropriate as the costs for each are predominantly capital expenditure related.

4. The revenue requirement calculation includes the typical items recovered in a cost of service calculation such as depreciation, total return on rate base including interest, equity and taxes, and other operating costs. The Company has used the 2007 Board Approved capital structure within the revenue requirement calculation, the same as that used within the GDAR deferral account treatment, as it is the underlying capital structure within base rates which are used in EGD's 2008-2012 Incentive Regulation approved rates mechanism.

5. The Company is proposing to recover $0.3 million as a one time billing adjustment in July, 2011 as shown in the proposed one time clearance balances at Exhibit C, Tab 1, Schedule 1, page 2, Columns 3 and 4. The determination of the 2011 annual revenue requirement associated with the 2008, 2009 and 2010 MPFDA is shown on pages 3 through 7 of this schedule.

ONTARIO UTILITY CAPITAL STRUCTURE
2008, 2009 & 2010 MPFDA IMPACTS

2007 Approved Capital Structure

Line No.		Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component
		%	%	%
1.	Long-term debt	59.65	7.31	4.36
2.	Short-term debt	1.68	4.12	0.07
3.		61.33		4.43
4.	Preference shares	2.67	5.00	0.13
5.	Common equity	36.00	8.39	3.02
6.		100.00		7.58

	($ 000's)	2008	2009	2010	2011
7.	Ontario Utility Income	(1.6)	(12.9)	(25.6)	(43.0)
8.	Rate base	204.3	1,038.8	1,838.0	2,333.5
9.	Indicated rate of return	(0.78)%	(1.24)%	(1.39)%	(1.84)%
10.	(Def.) / suff. in rate of return	(8.36)%	(8.82)%	(8.97)%	(9.42)%
11.	Net (def.) / suff.	(17.1)	(91.6)	(164.9)	(219.8)
12.	Gross (def.) / suff. (Note: 1)	(25.7)	(136.7)	(239.0)	(306.3)

Note: 1 Includes 2008 permit fees of $0.7 million, 2009 permit fees of $0.9 million, and 2010 permit fees of $0.9 million. Permit fees in 2011 and beyond will increase the prospective annual revenue requirements.

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY RATE BASE
2008, 2009 & 2010 MPFDA IMPACTS

Line No.	($ 000's)	2008	2009	2010	2011
	Property, plant, and equipment				
1.	Cost or redetermined value	207.0	1,070.6	1,937.1	2,535.3
2.	Accumulated depreciation	(2.7)	(31.8)	(99.1)	(201.8)
3.		204.3	1,038.8	1,838.0	2,333.5
	Allowance for working capital				
4.	Accounts receivable merchandise finance plan	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-
6.	Materials and supplies	-	-	-	-
7.	Mortgages receivable	-	-	-	-
8.	Customer security deposits	-	-	-	-
9.	Prepaid expenses	-	-	-	-
10.	Gas in storage	-	-	-	-
11.	Working cash allowance	-	-	-	-
12.		-	-	-	-
13.	Ontario utility rate base	204.3	1,038.8	1,838.0	2,333.5

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY INCOME
2008, 2009 & 2010 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011
	Revenue				
1.	Gas sales	-	-	-	-
2.	Transportation of gas	-	-	-	-
3.	Transmission and compression	-	-	-	-
4.	Other operating revenue	-	-	-	-
5.	Other income	-	-	-	-
6.	Total revenue	-	-	-	-
	Costs and expenses				
7.	Gas costs	-	-	-	-
8.	Operation and Maintenance	-	-	-	-
9.	Depreciation and amortization	10.7	48.6	86.7	111.6
10.	Municipal and other taxes	1.6	3.5	1.7	-
11.	Total costs and expenses	12.3	52.1	88.4	111.6
12.	Utility income before inc. taxes	(12.3)	(52.1)	(88.4)	(111.6)
	Income taxes				
13.	Excluding interest shield	(7.7)	(24.0)	(37.6)	(39.4)
14.	Tax shield on interest expense	(3.0)	(15.2)	(25.2)	(29.2)
15.	Total income taxes	(10.7)	(39.2)	(62.8)	(68.6)
16.	Ontario utility net income	(1.6)	(12.9)	(25.6)	(43.0)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2008, 2009 & 2010 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011
1.	Utility income before income taxes	(12.3)	(52.1)	(88.4)	(111.6)
	Add Backs				
2.	Depreciation and amortization	10.7	48.6	86.7	111.6
3.	Large corporation tax	-	-	-	-
4.	Other non-deductible items	-	-	-	-
5.	Any other add back(s)	-	-	-	-
6.	Total added back	10.7	48.6	86.7	111.6
7.	Sub total - pre-tax income plus add backs	(1.6)	(3.5)	(1.7)	-
	Deductions				
8.	Capital cost allowance - Federal	21.5	69.3	119.6	139.5
9.	Capital cost allowance - Provincial	21.5	69.3	119.6	139.5
10.	Items capitalized for regulatory purposes	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-
15.	Any other deduction(s)	-	-	-	-
16.	Total Deductions - Federal	21.5	69.3	119.6	139.5
17.	Total Deductions - Provincial	21.5	69.3	119.6	139.5
18.	Taxable income - Federal	(23.1)	(72.8)	(121.3)	(139.5)
19.	Taxable income - Provincial	(23.1)	(72.8)	(121.3)	(139.5)
20.	Income tax provision - Federal	(4.5)	(13.8)	(21.8)	(23.0)
21.	Income tax provision - Provincial	(3.2)	(10.2)	(15.8)	(16.4)
22.	Income tax provision - combined	(7.7)	(24.0)	(37.6)	(39.4)
23.	Part V1.1 tax	-	-	-	-
24.	Investment tax credit	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(7.7)	(24.0)	(37.6)	(39.4)
	Tax shield on interest expense				
26.	Rate base as adjusted	204.3	1,038.8	1,838.0	2,333.5
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	9.1	46.0	81.4	103.4
29.	Combined tax rate	33.500%	33.000%	31.000%	28.250%
30.	Income tax credit	(3.0)	(15.2)	(25.2)	(29.2)
31.	Total income taxes	(10.7)	(39.2)	(62.8)	(68.6)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY REVENUE REQUIREMENT
2008, 2009 & 2010 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011
	Cost of capital				
1.	Rate base	204.3	1,038.8	1,838.0	2,333.5
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	15.5	78.7	139.3	176.9
	Cost of service				
4.	Gas costs	-	-	-	-
5.	Operation and Maintenance	-	-	-	-
6.	Depreciation and amortization	10.7	48.6	86.7	111.6
7.	Municipal and other taxes	1.6	3.5	1.7	-
8.	Cost of service	12.3	52.1	88.4	111.6
	Misc. & Non-Op. Rev				
9.	Other operating revenue	-	-	-	-
10.	Other income	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-
	Income taxes on earnings				
12.	Excluding tax shield	(7.7)	(24.0)	(37.6)	(39.4)
13.	Tax shield provided by interest expense	(3.0)	(15.2)	(25.2)	(29.2)
14.	Income taxes on earnings	(10.7)	(39.2)	(62.8)	(68.6)
	Taxes on (def) / suff.				
15.	Gross (def.) / suff.	(25.7)	(136.7)	(239.0)	(306.3)
16.	Net (def.) / suff.	(17.1)	(91.6)	(164.9)	(219.8)
17.	Taxes on (def.) / suff.	8.6	45.1	74.1	86.5
18.	Revenue requirement	25.7	136.7	239.0	306.4
	Revenue at existing Rates				
19.	Gas sales	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.0	0.0	0.0	0.0
23.	Revenue at existing rates	0.0	0.0	0.0	0.0
24.	Gross revenue (def.) / suff.	(25.7)	(136.7)	(239.0)	(306.4)

Witnesses: K. Culbert
R. Small

TAX RATE AND RULE CHANGE VARIANCE ACCOUNT

1. Within the EB-2009-0172 Rate Order, the Board approved a 2010 Tax Rate and Rule Change Variance Account ("TRRCVA"). The purpose of the account was that in the event that actual tax rates and rules did not equate to those expected within the tax savings sharing mechanism embedded within the 2010 approved distribution revenue formula, the Company was to calculate the appropriate amounts which should be shared equally, based upon 2007 Board Approved base level benchmarks, and record the resulting variance in this account to be cleared to ratepayers.

2. Within the 2011 EB-2010-0146 proceeding, the Company provided and the Board approved, updated tax savings calculations for the years 2009 through 2012. Evidence in EB-2010-0146 (Exhibit C, Tab 1, Schedule 2, p. 4, Col. 3, Line 57) showed updated cumulative savings amounts of $8.87 million for 2009 and $15.56 million for 2010. Within that schedule, Columns 2 and 3, Line 58, showed the amounts actually being credited through rates of $9.6 million in 2009 and $15.8 million in 2010. As explained at page 3, paragraph 10 of that evidence, taking into account all known tax rate and rule changes at that time would result in $0.97 million being required to be debited into the 2010 TRRCVA for eventual clearance, which was approved by the Board. A copy of the then updated summary of forecast tax savings and sharing amounts, approved in EB-2010-0146, is reproduced at page 4 of this exhibit.

3. As a result of the implementation of the harmonized sales tax ("HST") on July 1, 2010, the EB-2010-0146 approved tax savings and sharing agreement requires a further update to account for the effects of the new HST. The analysis and explanation of the impacts of the new HST is provided in evidence at Exhibit B,

Witnesses: K. Culbert
R. Small

Tab 1, Schedule 5, which shows the forecast effect within each of 2010, 2011 and 2012.

4. The updated cumulative annual shared tax savings amounts for 2010 through 2012, as a result of incorporating the HST impact, is shown at Line 62, Columns 3 through 5 on page 3 of this exhibit. The EB-2010-0146 and most recent approved annual tax savings and sharing amounts are shown at Line 63 on page 3 and at Line 57 on page 4.

5. The impact for 2010 is that the previously approved debit of $0.97 million to the 2010 TRRCVA, (Lines 59 and 60, Col's. 2 and 3, p. 4 or Line 67, Col. 3, p. 3), now becomes $0.52 million (Line 68, Col. 3, p. 3). The currently updated anticipated amount to be credited within the 2011 TRRCVA is $1.2 million (Line 65, Col. 4, p. 3), which due to timing could not be incorporated into 2011 rates. For 2012, the Company will include an incremental credit amount of $4.58 million (Line 66, Col. 5, p. 3) as an adjustment in the development of the 2012 Incentive Revenue formula, which will reflect the current anticipated cumulative impact of tax savings and sharing. The Company is requesting clearance of the 2010 TRRCVA account along with the other deferral and variance accounts shown in Exhibit C, Tab 1, Schedule 1, page 2, to be cleared to ratepayers commencing July 1, 2011.

Witnesses: K. Culbert
R. Small

Table 1

Updated Summary - Sharing of Tax Change Forecast Amounts

(2011 Approved Sharing amounts updated for changes resulting from HST impacts)

Line No.		Col. 1 2008	Col. 2 2009	Col. 3 2010	Col. 4 2011	Col. 5 2012	Col. 6
	Tax Related Amounts Forecast from CCA Rate Changes **($ Millions)**						
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45/50) - Opening UCC Balance	1.54	2.24	1.14	0.51	1.64	
6.	New purchases (2007 Board Approved additions) - **with update for new Class 52**	2.13	2.13	2.13	2.13	2.13	
7.	**Re-grouping of amounts eligible for Class 52 (included at line 11)**	-	(1.95)	(2.13)	(0.18)	-	
8.	Capital Cost Allowance (CCA) at 55% -2007 Federal Budget tax rule CCA rate	1.43	1.28	0.63	0.82	1.49	
9.	Closing Undepreciated Capital Cost (UCC)	2.24	1.14	0.51	1.64	2.28	
10.	Computer Equipment (**New Class 52**) - Opening UCC Balance	-	-	-	-	-	
11.	New purchases (2007 Board Approved additions) - **with update for new Class 52**	-	1.95	2.13	0.18	-	
12.	Capital Cost Allowance (CCA) at 100% -2007 Federal Budget tax rule CCA rate	-	1.95	2.13	0.18	-	
13.	Closing Undepreciated Capital Cost (UCC)	-	-	-	-	-	
14.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.76	687.71	898.86	1101.57	
15.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
16.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
17.	Closing Undepreciated Capital Cost (UCC)	467.76	687.71	898.86	1101.57	1296.16	
18.	Distribution Assets (Class 51) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
19.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
20.	Capital Cost Allowance (CCA) at 6% -2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
21.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
22.	CCA Difference	7.27	12.82	15.85	17.29	20.67	
23.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	31.00%	28.25%	26.25%	
24.	Tax Impact	2.44	4.23	4.91	4.89	5.43	
25.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.65	6.31	7.12	6.81	7.36	31.26
26.	Incremental Amount	3.65	2.66	0.81	(0.31)	0.55	
27.	**50% of the Amount to Reduce Rates**	**$1.83**	**$1.33**	**$0.40**	**-$0.16**	**$0.28**	
	Tax Related Amounts Forecast from Income Tax Rate Changes						
28.	Taxable Income (2007 Board Approved, Final Rate Order, App.A, S3,P3,L15)	355.6	355.6	355.6	355.6	355.6	
29.	Gross Deficiency (2007 Board Approved, Final Rate Order, App.A, S1,P1,L7)	42.7	42.7	42.7	42.7	42.7	
30.	Interest Expense (2007 Board Approved, Final Rate Order, App.A, S3,P3,L25)	(165.90)	(165.90)	(165.90)	(165.90)	(165.90)	
31.	Board Approved Taxable Income for Income Tax Expense Calculation	232.40	232.40	232.40	232.40	232.40	
32.	2007 Approved Tax Rate (2007 Board Approved, Final Rate Order, App.A, S3,P3,L27)	36.12%	36.12%	36.12%	36.12%	36.12%	
33.	Anticipated Tax Rates During the IR Term	33.50%	33.00%	31.00%	28.25%	26.25%	
34.	Tax Rate Variance	2.62%	3.12%	5.12%	7.87%	9.87%	
35.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	11.90	18.29	22.94	
36.	Grossed-up Tax Savings	9.16	10.82	17.25	25.49	31.11	93.83
37.	Incremental Amount	9.16	1.66	6.43	8.24	5.62	
38.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$3.22**	**$4.12**	**$2.80**	
	Capital Tax Related Amounts Forecast from Capital Tax Rate Changes						
39.	2007 Taxable Capital as Filed (EB-2006-0034, D3,T1,S1,P6,L7)	3,571.0	3,571.0	3,571.0	3,571.0	3,571.0	
40.	2007 Decision and Settlement Agreement Adjustments to Taxable Capital	(118.8)	(118.8)	(118.8)	(118.8)	(118.8)	
41.	2007 Board Approved Taxable Capital	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
42.	2007 Board Approved Capital Tax Rate (EB-2006-0034, D3,T1,S1,P6,L8)	0.285%	0.285%	0.285%	0.285%	0.285%	
43.	Anticipated Capital Tax Rates During the IR Term	0.225%	0.225%	0.075%	0.000%	0.000%	
44.	Capital Tax Rate Variance	0.060%	0.060%	0.210%	0.285%	0.285%	
45.	Annual Capital Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	2.07	2.07	7.25	9.84	9.84	31.07
46.	Incremental Amount	2.07	0.00	5.18	2.59	0.00	
47.	**50% of the Amount to Reduce Rates**	**$1.03**	**$0.00**	**$2.58**	**$1.30**	**$0.00**	
	Capital Tax Related Amounts Forecast from Taxable Capital Changes						
48.	2007 Board Approved Taxable Capital (Row 41 above)	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
49.	Revised 2007 Board Approved Taxable Capital Resutling From Rule Changes	3,452.2	4,098.1	4,098.1	4,098.1	4,098.1	
50.	Incremental Taxable Capital	0.0	(645.9)	(645.9)	(645.9)	(645.9)	
51.	Anticipated Capital Tax Rates During the IR Term (Row 43 above)	0.225%	0.225%	0.075%	0.000%	0.000%	
52.	Annual Capital Tax Increase vs. 2007 Approved Taxes (Cumulative Total Forecast)	0.00	(1.45)	(0.48)	0.00	0.00	(1.93)
53.	Incremental Amount	0.00	(1.45)	0.97	0.48	0.00	
54.	**50% of the Amount to Reduce Rates**	**$0.00**	**($0.73)**	**$0.49**	**$0.24**	**$0.00**	
	Revenue Requirement Amounts Forecast from HST Change Impacts						
55.	Net cumulative revenue requirement benefit (Ex.B, T1, S.5, pg.1, line 11)	-	-	0.6	1.7	2.2	
56.	Income tax rates	-	-	31.00%	28.25%	26.25%	
57.	Gross cumulative revenue requirement benefit (Ex.B, T1, S.5, pg.1, line 12)	-	-	0.9	2.4	3.0	6.30
58.	Incremental Amount	-	-	0.9	1.5	0.6	
59.	**50% of the Amount to Reduce Rates**	-	-	**$0.45**	**$0.75**	**$0.30**	
60.	**Cumulative Total Forecast Tax Related Amount (lines 25+36+45+52+57)**	**14.88**	**17.75**	**32.04**	**44.54**	**51.31**	160.53
61.	**Total Incremental Ratepayer Amounts into rates (lines 27+38+47+54+59)**	**$7.44**	**$1.43**	**$7.14**	**$6.25**	**$3.38**	
62.	**Updated of Annual Ratepayer & Company Shareholder Tax Savings (50% of row 60)**	**$7.44**	**$8.87**	**$16.01**	**$22.26**	**$25.64**	$80.22
63.	**2011, EB-2010-0146 Approved / Updated Agreement Annual Ratepayer Tax Savings**	***$7.44***	***$8.87***	***$15.56***	***$21.06***	***$24.14***	*$77.07*
64.	Incremental 2010 TRRCVA credit from the HST change ($16.01M - $15.56M) (col.3, line 62 - 63)			0.45			
65.	2011 TRRCVA credit from the HST change ($22.26M - $21.06M) (col.4, line 62 - col.4, line 63)				$1.20		
66.	Ratepayer share of 2012 incremental tax amounts ($25.64M - $21.06M) (col.5, line 62 - col.4, line 63)					$4.58	
67.	Amounts previously Approved in EB-2010-0146 to be debited into the 2010 TRRCVA			(0.97)			
68.	Net updated 2010 TRRCVA debit amount recoverable from ratepayers ((0.97) - 0.45) (col.3, line 64 - col.3, line 67)			(0.52)			

Table 2

2011, Updated Summary - Sharing of Tax Change Forecast Amounts

(Incorporates changes in provincial taxable capital base in 2009 and 2010)

Line No.	**Tax Related Amounts Forecast from CCA Rate Changes** **($ Millions)**	Col. 1 **2008**	Col. 2 **2009**	Col. 3 **2010**	Col. 4 **2011**	Col. 5 **2012**	Col. 6
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45/50) - Opening UCC Balance	1.54	2.24	1.14	0.51	1.64	
6.	New purchases (2007 Board Approved additions) - **with update for new Class 52**	2.13	2.13	2.13	2.13	2.13	
7.	**Re-grouping of amounts eligible for Class 52 (included at line 11)**	-	(1.95)	(2.13)	(0.18)	-	
8.	Capital Cost Allowance (CCA) at 55% -2007 Federal Budget tax rule CCA rate	1.43	1.28	0.63	0.82	1.49	
9.	Closing Undepreciated Capital Cost (UCC)	2.24	1.14	0.51	1.64	2.28	
10.	Computer Equipment (**New Class 52**) - Opening UCC Balance	-	-	-	-	-	
11.	New purchases (2007 Board Approved additions) - **with update for new Class 52**	-	1.95	2.13	0.18	-	
12.	Capital Cost Allowance (CCA) at 100% -2007 Federal Budget tax rule CCA rate	-	1.95	2.13	0.18	-	
13.	Closing Undepreciated Capital Cost (UCC)	-	-	-	-	-	
14.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.76	687.71	898.86	1101.57	
15.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
16.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
17.	Closing Undepreciated Capital Cost (UCC)	467.76	687.71	898.86	1101.57	1296.16	
18.	Distribution Assets (Class 51) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
19.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
20.	Capital Cost Allowance (CCA) at 6% -2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
21.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
22.	CCA Difference	7.27	12.82	15.85	17.29	20.67	
23.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	31.00%	28.25%	26.25%	
24.	Tax Impact	2.44	4.23	4.91	4.89	5.43	
25.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.65	6.31	7.12	6.81	7.36	31.26
26.	Incremental Amount	3.65	2.66	0.81	(0.31)	0.55	
27.	**50% of the Amount to Reduce Rates**	**$1.83**	**$1.33**	**$0.40**	**-$0.16**	**$0.28**	
	Tax Related Amounts Forecast from Income Tax Rate Changes						
28.	Taxable Income (2007 Board Approved, Final Rate Order, App.A, S3,P3,L15)	355.6	355.6	355.6	355.6	355.6	
29.	Gross Deficiency (2007 Board Approved, Final Rate Order, App.A, S1,P1,L7)	42.7	42.7	42.7	42.7	42.7	
30.	Interest Expense (2007 Board Approved, Final Rate Order, App.A, S3,P3,L25)	(165.90)	(165.90)	(165.90)	(165.90)	(165.90)	
31.	Board Approved Taxable Income for Income Tax Expense Calculation	232.40	232.40	232.40	232.40	232.40	
32.	2007 Approved Tax Rate (2007 Board Approved, Final Rate Order, App.A, S3,P3,L27)	36.12%	36.12%	36.12%	36.12%	36.12%	
33.	Anticipated Tax Rates During the IR Term	33.50%	33.00%	31.00%	28.25%	26.25%	
34.	Tax Rate Variance	2.62%	3.12%	5.12%	7.87%	9.87%	
35.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	11.90	18.29	22.94	
36.	Grossed-up Tax Savings	9.16	10.82	17.25	25.49	31.11	93.83
37.	Incremental Amount	9.16	1.66	6.43	8.24	5.62	
38.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$3.22**	**$4.12**	**$2.80**	
	Capital Tax Related Amounts Forecast from Capital Tax Rate Changes						
39.	2007 Taxable Capital as Filed (EB-2006-0034, D3,T1,S1,P6,L7)	3,571.0	3,571.0	3,571.0	3,571.0	3,571.0	
40.	2007 Decision and Settlement Agreement Adjustments to Taxable Capital	(118.8)	(118.8)	(118.8)	(118.8)	(118.8)	
41.	2007 Board Approved Taxable Capital	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
42.	2007 Board Approved Capital Tax Rate (EB-2006-0034, D3,T1,S1,P6,L8)	0.285%	0.285%	0.285%	0.285%	0.285%	
43.	Anticipated Capital Tax Rates During the IR Term	0.225%	0.225%	0.075%	0.000%	0.000%	
44.	Capital Tax Rate Variance	0.060%	0.060%	0.210%	0.285%	0.285%	
45.	Annual Capital Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	2.07	2.07	7.25	9.84	9.84	31.07
46.	Incremental Amount	2.07	0.00	5.18	2.59	0.00	
47.	**50% of the Amount to Reduce Rates**	**$1.03**	**$0.00**	**$2.58**	**$1.30**	**$0.00**	
	Capital Tax Related Amounts Forecast from Taxable Capital Changes						
48.	2007 Board Approved Taxable Capital (Row 41 above)	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
49.	Revised 2007 Board Approved Taxable Capital Resutling From Rule Changes	3,452.2	4,098.1	4,098.1	4,098.1	4,098.1	
50.	Incremental Taxable Capital	0.0	(645.9)	(645.9)	(645.9)	(645.9)	
51.	Anticipated Capital Tax Rates During the IR Term (Row 43 above)	0.225%	0.225%	0.075%	0.000%	0.000%	
52.	Annual Capital Tax Increase vs. 2007 Approved Taxes (Cumulative Total Forecast)	0.00	(1.45)	(0.48)	0.00	0.00	(1.93)
53.	Incremental Amount	0.00	(1.45)	0.97	0.48	0.00	
54.	**50% of the Amount to Reduce Rates**	**$0.00**	**($0.73)**	**$0.49**	**$0.24**	**$0.00**	
55.	**Cumulative Total Forecast Tax Related Amount (lines 25+36+45+52)**	**14.88**	**17.75**	**31.14**	**42.14**	**48.31**	154.23
56.	**Total Incremental Ratepayer Amounts into rates (lines 27+38+47+54)**	**$7.44**	**$1.43**	**$6.69**	**$5.50**	**$3.08**	
57.	**2011, Update of Annual Ratepayer & Company Shareholder Tax Savings (50% of row 55)**	**$7.44**	**$8.87**	**$15.56**	**$21.06**	**$24.14**	$77.07
58.	**2010, EB-2009-0172 Approved / Updated Agreement Annual Ratepayer Tax Savings**	***$7.44***	***$9.60***	***$15.80***	***$21.06***	***$24.14***	*$78.04*
59.	Amount to be debited to 2010 TRRCVA for 2009 update ($8.87M - $9.60M) (col.2, line 57 - 58)		($0.73)				
60.	Amount to be debited to 2010 TRRCVA for 2010 update ($15.56M - $15.80M) (col.3, line 57 - 58)			(0.24)			
61.	Ratepayer share of 2011 incremental tax amounts ($21.06M - $15.80M) (col.4, line 58 - col.3, line 58)				$5.26		
62.	Ratepayer share of 2012 incremental tax amounts ($24.14M - $21.06M) (col.5, line 57 - col.4, line 57)					$3.08	

2010 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2010 Average Use True-up Variance Account ("AUTUVA") amount.

2. Table 1 of Appendix A provides details of the calculations that result in the amount of $2.15 million that will be credited to ratepayers. The refund is primarily attributable to net rate switching gains from a contract rate (or transfer gains) to Rate 6, partially offset by the shortfall in residential average use variances.

3. Tables 2 and 3 in the Appendix illustrate that the majority of the net rate switching gains from a contract rate to Rate 6 was in consequence of unexpected production cuts or plant consolidation due to the ongoing impact of the economic recovery from the rapidly deteriorating economic conditions experienced since October 2008 is slower than anticipated. Please refer to EB-2009-0172, Exhibit B, Tab 1, Schedule 5, pages 15 to 20 for additional explanation.

4. Besides the weak economic factor mentioned above, the continuing actual conservation and energy efficiency trends also contributed to the decline in residential average use, which is consistent with past experience.

5. As indicated in the 2010 volume budget evidence filed at EB-2009-0172, Exhibit B, Tab 1, Schedule 5, pages 12 to 14, Rate 1 average use budget numbers were on the high side due to difficulties encountered in identifying and applying the estimated energy savings resulting from various energy efficiency and conservation initiatives or trends as follows:

- an increase in the minimum performance level, Annual Fuel Utilization Efficiency ("AFUE"), for residential gas-fired furnaces will be 90% (high-efficiency) instead of the previously 78% (medium-efficiency) effective December 31, 2009;
- the new 2006 Building Code effective December 31, 2006, further changes to this 2006 Building Code effective December 31, 2008 and requiring near-full-height basement insulation effective December 31, 2009;
- other green energy technology, various conservation initiatives originated by customers themselves or promoted by government programs (e.g., Ontario Green Energy Act, ecoENERGY Retrofit, Solar H2Ottawa, Ontario Home Energy Audit and Retrofit, and Ontario Solar Thermal Heating Incentive); and
- the potential adverse impact of further self-imposed energy conservation activities undertaken by customers with the implementation of the Harmonized Sales Tax ("HST") in 2010 as suggested by Ontario Finance Minister.[1] Prior to July 2010, natural gas customers were exempt from the provincial sales tax (8%). However, with the implementation of the blended tax rate effective July 2010, home energy costs are increased by 8% all else being equal. As a result, customers might perceive this as a further increase in gas charges.

6. Further rate class detail and explanations are provided at Exhibit B, Tab 2, Schedules 2 to 4.

7. As filed in response to VECC's Interrogatory at EB-2008-0219, Exhibit I, Tab 7, Schedule 8, part(d), the numerical calculation of Table 1 was previously illustrated and explained. In accordance with the settlement agreement filed at EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, pages 15 and 16 and EB-2007-0615,

[1] Ontario matching energy incentives. Toronto Star, 31, Mar. 2009. http://www.thestar.com/printArticle/610800.

Decision and Rate Order, Appendix C, page 25, the purpose of the AUTUVA is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6, and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism ("LRAM"), extended by the average use volume variance per customer and the number of customers.

8. As was the case in previous rate case proceedings, the audited actual volume savings of DSM activities will not be available until later in the 2011 year. Therefore, 2010 Board Approved Budget DSM volumes still represent an appropriate estimate for 2010.

9. Tables 4 and 5 of Appendix A illustrate the corresponding actual weather normalized volumes and actual customers for both Rate 1 and Rate 6 that underpin Table 1's calculation. Further rate class detail and explanations are provided at Exhibit B, Tab 3, Schedule 2.

TABLE 1
2010 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

Exhibit Reference:	EB-2009-0172, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 21	Tables 4-5 on pages 4-5		EB-2009-0172, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 1		EB-2009-0172, Exhibit B, Tab 1, Schedule 5, Tables 3-6				Unit Rate of the Revenue Impact, exclusive of gas costs	
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
			=Col. 2-1		=Col. 3*4			=Col. 7-6	=Col. 5-8		=Col. 9*10
Rate Class	2010 Budget Annual Use (m^3)	2010 Normalized Actual Annual Use (m^3)	Normalized Usage Variance (m^3)	Budget Customer Meters	Normalized Volumetric Variance (10^6m^3)	2010 DSM Budget (10^6m^3)	2010 DSM Actual (10^6m^3)	DSM Volumetric Variance (10^6m^3)	Normalized Volumetric Variance Excluding DSM (10^6m^3)	Unit Rate ($/$m^3$)	AUTUVA: Revenue Impact, Exclusive of Gas Costs ($ millions)
1	2,622	2,579	(43)	1,772,699	(75.8)	(13.7)	(13.7)	0.0	(75.8)	0.0606	(4.59)
6	27,949	29,106	1,157	158,257	183.0	(26.6)	(26.6)	0.0	183.0	0.0368	6.74
Total					107.2	(40.3)	(40.3)	0.0	107.2		2.15

TABLE 2
CUSTOMER MIGRATION FROM CONTRACT RATE CLASS TO RATE 6
BETWEEN 2010 ACTUAL AND 2010 BOARD APPROVED BUDGET

Table 2 - Customer Migration from Contract Rate to Rate 6
Between 2010 Actual and 2010 Board Approved Budget

1. Customers migrated to rate 6 due to rate design chages

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	35	Apartment	23.1
	1	Education Services	1.6
Total	36		24.7

2. Customers migrated to rate 6 due to production cuts or plant consolidation

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	1	All Other Industrial	2.8
	1	Asphalt	0.7
	7	Chemical and Chemical Products	10.3
	1	Construction Industries	1.0
	3	Food, Beverage, Drug & Tobacco	6.9
	2	Government Services	36.1
	3	Greenhouses/Agriculture	1.5
	2	Non-Metallic Mineral Products	2.3
	9	Primary Metal & Machinery	14.9
	6	Pulp & Paper	9.0
	1	Textile Products	1.0
	5	Transportation Equipment	9.6
	4	Wholesale & Retail Trade	3.3
Total	45		99.4
Grand Total	**81**		**124.1**

*The number here only counts the billing account number which is different from meter count.
This count does not reflect the timing of the migration.

TABLE 3
CUSTOMER MIGRATION FROM RATE 6 TO CONTRACT RATE CLASS
BETWEEN 2010 ACTUAL AND 2010 BOARD APPROVED BUDGET

1. Customers already migrated to Rate 6 in 2010 (Timing)

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(3)	All Other Industrial	(0.5)
	(14)	Apartment	(9.7)
	(1)	Asphalt	(0.7)
	(1)	Business & Financial Service Industries	(0.5)
	(1)	Electronics/High Tech	(0.6)
	(1)	Primary Metal & Machinery	(1.6)
	(3)	Rubber Products	(1.4)
	(1)	Transportation and Storage and Utilities	(0.1)
	(2)	Transportation Equipment	(1.4)
	(1)	Wood & Furniture Industries	(0.9)
Total	(28)		(17.4)

*The number here only counts the billing account number which is different from meter count. This count does not reflect the timing of the migration.

TABLE 4
GENERAL SERVICE RATE 1
2010 ACTUAL - NORMALIZED VOLUME, CUSTOMERS, AVERAGE USE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Exhibit Reference
Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1.1	Normalized Volumes (10^6m^3)	775.9	779.9	682.8	479.7	281.7	140.6	92.7	100.2	109.7	174.3	337.1	618.0	4,572.6	Exhibit B, Tab 3, Schedule 2
1.2	Customer Meters	1,765,549	1,767,519	1,772,115	1,776,130	1,767,481	1,766,650	1,767,812	1,771,241	1,773,050	1,773,946	1,781,555	1,786,993	1,772,503	Exhibit B, Tab 3, Schedule 4, Col. 1 Item 1.1
1.3	Average Use per Customer (m^3)	439	441	385	270	159	80	52	57	62	98	189	346	2,579	

TABLE 5
GENERAL SERVICE RATE 6
2010 ACTUAL - NORMALIZED VOLUME, CUSTOMERS, AVERAGE USE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Exhibit Reference
Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1.1	Normalized Volumes (10^6m^3)	665.3	749.6	716.0	523.5	259.8	136.8	99.7	94.8	115.4	163.5	315.5	620.9	4,460.8	Exhibit B, Tab 3, Schedule 2
1.2	Customer Meters	152,429	154,094	155,456	156,567	155,497	156,094	154,798	153,116	151,315	150,214	149,509	149,417	153,209	Exhibit B, Tab 3, Schedule 4, Col. 1 Item 1.2
1.3	Average Use per Customer (m^3)	4,365	4,865	4,606	3,344	1,671	877	644	619	763	1,088	2,110	4,156	29,106	

2010
ENBRIDGE GAS DISTRIBUTION
ONTARIO HEARING COSTS
VARIANCE ACCOUNT

Line No.	Test Year Proceeding Costs	Col. 1 Baseline Regulatory Cost Budget ($000's)	Col. 2 2010 Regulatory Costs Incurred* ($000's)	Col. 3 Variance ($000's)
1.	Legal	840.0	698.0	
2.	Intervenor	1,155.0	488.5	
3.	Ontario Energy Board	4,040.0	3,363.2	
4.	Consultants	500.0	169.8	
5.	Transcripts, newspaper notices, printing, other	420.0	160.1	
6.	Sub-total	6,955.0	4,879.6	
7.	Other proceedings	1,887.5	1,055.0	
8.	2009 Agreed to OHCVA threshold reduction	(3,000.0)	-	
9.	Actual versus OHCVA threshold variance	5,842.5	5,934.6	92.1

Line No.	Breakdown of Other Proceedings (Line 7 above)	
10.	DSM Input Assumptions EB-2010-0202	345.4
11.	CIS & Open Bill Consultatives	326.0
12.	Storage & Transportation Access Rule EB-2008-0052	167.2
13.	Regulatory Cost Alloc Methodology Review ("RCAM")	112.5
14.	Return on Equity - Cost of Capital EB-2009-0084 (intervenor costs)	59.3
15.	Consultation on Energy Issues / Low Income Consumers EB-2008-0150	44.6
16.		1,055.0

Witnesses: K. Culbert
R. Small

CLEARANCE OF 2010 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The Company is proposing to clear 2010 deferral and variance account balances as well as 2009 DSM-related account balances to customers during the July 2011 billing cycle.

2. With the replacement of GST with HST on July 1, 2010, it is necessary to ensure that appropriate tax rates, HST or GST, are applied to bill adjustments to customers stemming from the clearance of the 2010 deferral and variance account balances when considering Canada Revenue Agency requirements. As a result, two sets of unit rates are required for the disposition of the 2010 deferral and variance accounts. Unit rates were separately derived for accounts where GST is applicable and for accounts where HST is applicable. The supporting schedules group accounts according to the type of tax that applies.

3. The GST-applicable and HST-applicable unit rates for each type of service are shown at Exhibit C, Tab 2, Schedule 2, page 1. Each unit rate will be applied to each customer's actual 2010 consumption volume for the period January 1, 2010 to December 31, 2010, and will be recovered or remitted in July 2011.

4. Exhibit C, Tab 2, Schedule 2 shows the derivation of the proposed unit rates:
   - Page 2 determines the balance (principal and interest) to be cleared for each Board-approved 2010 deferral and variance account; account balances are separated to show which ones are GST-applicable and HST-applicable on Columns 3 and 4;
   - Pages 3 and 4 allocate account balances to the rate classes based on cost drivers for each type of account;

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

- Pages 5 and 6 summarize the allocation of account balances by rate class and type of service; and
- Pages 7 and 8 derive the unit rates for the clearance / disposition by rate class and type of service. The unit rates are derived using actual 2010 consumption volumes for each rate class and each type of service.

5. The table on page 9 displays the bill adjustments (showing both GST-applicable and HST-applicable unit rates) in July 2011 for typical customers resulting from the clearance of the 2010 deferral and account balances. These bill adjustments will be shown as separate line items on customers' July 2011 bills so that the appropriate tax rate (GST/HST) can be applied.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

UNIT RATE AND TYPE OF SERVICE: CLEARING IN JULY 2011

		COL.1 GST-Applicable (¢/m³)	COL.2 HST-Applicable (¢/m³)
Bundled Services:			
RATE 1	- SYSTEM SALES	0.2003	(0.1114)
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	0.2003	(0.0627)
	- WESTERN T-SERVICE	0.2003	(0.1114)
RATE 6	- SYSTEM SALES	0.0260	(0.2733)
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0260	(0.2246)
	- WESTERN T-SERVICE	0.0260	(0.2733)
RATE 9	- SYSTEM SALES	0.0881	(0.7500)
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0881	(0.7014)
	- WESTERN T-SERVICE	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.4142	(0.1001)
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	0.4142	(0.0515)
	- WESTERN T-SERVICE	0.4142	(0.1001)
RATE 110	- SYSTEM SALES	0.2130	0.0004
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	0.2130	0.0490
	- WESTERN T-SERVICE	0.2130	0.0004
RATE 115	- SYSTEM SALES	(0.0020)	0.0137
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0020)	0.0623
	- WESTERN T-SERVICE	(0.0020)	0.0137
RATE 135	- SYSTEM SALES	(0.0859)	0.0164
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0859)	0.0650
	- WESTERN T-SERVICE	(0.0859)	0.0164
RATE 145	- SYSTEM SALES	0.0556	(0.0112)
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0556	0.0374
	- WESTERN T-SERVICE	0.0556	(0.0112)
RATE 170	- SYSTEM SALES	0.0488	0.0118
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0488	0.0605
	- WESTERN T-SERVICE	0.0488	0.0118
RATE 200	- SYSTEM SALES	(0.0185)	(0.0273)
	- BUY/SELL	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0185)	0.0213
	- WESTERN T-SERVICE	0.0000	0.0000
Unbundled Services:			
RATE 125	- All	0.2373	(1.8415)
	- Customer-specific ($)		$26,300
RATE 300	- All	1.3584	(9.1647)

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

Determination of Balances to be Cleared from the 2010 Deferral and Variance Accounts

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL for CLEARING -GST ($000)	COL. 4 TOTAL for CLEARING -HST ($000)
1.	TRANSACTIONAL SERVICES D/A	(7,264.5)	(64.3)		(7,328.8)
2.	UNACCOUNTED FOR GAS V/A	8,729.4	64.2		8,793.6
3.	STORAGE AND TRANSPORTATION D/A	(531.8)	(4.5)		(536.3)
4.	DEFERRED REBATE ACCOUNT	(2,387.1)	0.8	(2,386.3)	
5.	DEMAND SIDE MANAGEMENT 2009	1,165.1	12.8	1,177.9	
6.	LOST REVENUE ADJ MECHANISM 2009	(45.7)	(0.5)	(46.2)	
7.	SHARED SAVINGS MECHANISM 2009	5,364.2	39.5	5,403.7	
8.	CLASS ACTION SUIT D/A	4,709.5	463.8	5,173.3	
9.	ONTARIO HEARING COSTS V/A	92.1	0.6		92.7
10.	GAS DISTRIBUTION ACCESS RULE D/A	2,904.4	0.0		2,904.4
11.	AVERAGE USE TRUE-UP V/A	(2,145.2)	(15.7)		(2,160.9)
12.	IFRS TRANSITION COSTS D/A	2,080.6	25.2	2,105.8	
13.	UNBUNDLED RATE IMPLEMENTATION COST D/A	144.1	1.4		145.5
14.	MUNICIPAL PERMIT FEES D/A	306.3	0.0		306.3
15.	OPEN BILL SERVICE D/A	87.7	7.9	95.6	
16.	OPEN BILL ACCESS V/A	79.4	4.4	83.8	
17.	EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A	(251.9)	(1.8)		(253.7)
18.	TAX RATE & RULE CHANGE V/A	516.1	5.3		521.4
19.	EARNINGS SHARING MECHANISM	(17,100.0)	(136.1)		(17,236.1)
20.	TOTAL	(3,547.3)	403.0	11,607.6	(14,751.9)
21.	TOTAL FOR CLEARING		(3,144.3)		(3,144.3)

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

Classification and Allocation of Deferral and Variance Account Balances - GST Applicable

ITEM NO.		COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DISTRIBUTION REV REQ (DRR) ($000)	COL. 8 DIRECT ($000)	COL. 9 NUMBER OF CUSTOMERS ($000)	COL. 10 RATE BASE ($000)
	CLASSIFICATION										
1.	**DEFERRED REBATE ACCOUNT**	(2,386.3)			(2,386.3)						
2.	**DEMAND SIDE MANAGEMENT 2009**	1,177.9							1,177.9		
3.	**LOST REVENUE ADJ MECHANISM 2009**	(46.2)							(46.2)		
4.	**SHARED SAVINGS MECHANISM 2009**	5,403.7							5,403.7		
5.	**CLASS ACTION SUIT D/A**	5,173.3								5,173.3	
6.	**IFRS TRANSITION COSTS D/A**	2,105.8						2,105.8			
7.	**OPEN BILL SERVICE D/A**	95.6								95.6	
8.	**OPEN BILL ACCESS V/A**	83.8								83.8	
9.	**TOTAL**	11,607.6	0.0	0.0	(2,386.3)	0.0	0.0	2,105.8	6,535.4	5,352.7	0.0
	ALLOCATION										
1.1	RATE 1	8,840.7	0.0	0.0	(965.2)	0.0	0.0	1,426.9	3,453.5	4,925.4	0.0
1.2	RATE 6	1,129.9	0.0	0.0	(949.4)	0.0	0.0	593.7	1,059.9	425.7	0.0
1.3	RATE 9	1.0	0.0	0.0	(0.3)	0.0	0.0	1.2	0.0	0.1	0.0
1.4	RATE 100	93.6	0.0	0.0	(4.9)	0.0	0.0	3.1	95.4	0.1	0.0
1.5	RATE 110	1,197.9	0.0	0.0	(123.0)	0.0	0.0	23.6	1,296.7	0.6	0.0
1.6	RATE 115	(9.4)	0.0	0.0	(104.5)	0.0	0.0	11.0	84.0	0.1	0.0
1.7	RATE 125	16.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0
1.8	RATE 135	(62.7)	0.0	0.0	(16.0)	0.0	0.0	2.0	(48.8)	0.1	0.0
1.9	RATE 145	129.8	0.0	0.0	(51.0)	0.0	0.0	11.9	168.4	0.5	0.0
1.10	RATE 170	301.1	0.0	0.0	(135.0)	0.0	0.0	9.6	426.3	0.1	0.0
1.11	RATE 200	(31.4)	0.0	0.0	(37.1)	0.0	0.0	5.7	0.0	0.0	0.0
1.12	RATE 300	1.2	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0
1.		11,607.6	0.0	0.0	(2,386.3)	0.0	0.0	2,105.8	6,535.4	5,352.7	0.0

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

Classification and Allocation of Deferral and Variance Account Balances -- HST Applicable

ITEM NO.		COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DISTRIBUTION REV REQ (DRR) ($000)	COL. 8 DIRECT ($000)	COL. 9 NUMBER OF CUSTOMERS ($000)	COL. 10 RATE BASE ($000)
	CLASSIFICATION										
1.	**TRANSACTIONAL SERVICES D/A**	(7,328.8)	(3,273.9)			(1,994.1)	(2,060.8)				
2.	**UNACCOUNTED FOR GAS V/A**	8,793.6			8,793.6						
3.	**STORAGE AND TRANSPORTATION D/A**	(536.3)				(263.7)	(272.6)				
4.	**ONTARIO HEARING COSTS V/A**	92.7									92.7
5.	**GAS DISTRIBUTION ACCESS RULE D/A**	2,904.4								2,904.4	
6.	**AVERAGE USE TRUE-UP V/A**	(2,160.9)							(2,160.9)		
7.	**UNBUNDLED RATE IMPLEMENTATION COST D/A**	145.5								145.5	
8.	**MUNICIPAL PERMIT FEES D/A**	306.3									306.3
9.	**EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A**	(253.7)								(253.7)	
10.	**TAX RATE & RULE CHANGE V/A**	521.4									521.4
11.	**EARNINGS SHARING MECHANISM**	(17,236.1)						(17,236.1)			
12.	**TOTAL**	(14,751.9)	(3,273.9)	0.0	8,793.6	(2,257.9)	(2,333.4)	(17,236.1)	(2,160.9)	2,796.2	920.4
	ALLOCATION										
1.1	RATE 1	(4,494.3)	(1,725.5)	0.0	3,556.7	(1,094.6)	(1,228.3)	(11,678.9)	4,613.3	2,439.0	624.0
1.2	RATE 6	(11,101.2)	(1,347.7)	0.0	3,498.7	(1,037.2)	(1,056.5)	(4,859.7)	(6,774.2)	210.8	264.5
1.3	RATE 9	(8.8)	(0.5)	0.0	1.0	(0.0)	(0.0)	(10.1)	0.0	0.0	0.9
1.4	RATE 100	(16.8)	(5.1)	0.0	18.2	(4.7)	(5.5)	(25.3)	0.0	4.2	1.4
1.5	RATE 110	208.9	(66.7)	0.0	453.2	(2.8)	(16.0)	(193.3)	0.0	25.7	8.9
1.6	RATE 115	294.1	(3.7)	0.0	385.1	0.0	(4.6)	(89.9)	0.0	3.9	3.3
1.7	RATE 125	(45.3)	0.0	0.0	0.0	0.0	0.0	(131.0)	0.0	79.4	6.3
1.8	RATE 135	34.2	(13.3)	0.0	58.8	0.0	0.0	(16.1)	0.0	4.3	0.4
1.9	RATE 145	56.6	(30.7)	0.0	187.9	(30.4)	0.0	(97.1)	0.0	22.7	4.2
1.10	RATE 170	349.4	(23.8)	0.0	497.3	(53.8)	0.0	(78.8)	0.0	4.9	3.4
1.11	RATE 200	(20.7)	(56.9)	0.0	136.7	(34.2)	(22.5)	(46.3)	0.0	0.1	2.3
1.12	RATE 300	(7.9)	0.0	0.0	0.0	0.0	0.0	(9.6)	0.0	1.1	0.6
1.		(14,751.9)	(3,273.9)	0.0	8,793.6	(2,257.9)	(2,333.4)	(17,236.1)	(2,160.9)	2,796.2	920.4

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

ALLOCATION BY TYPE OF SERVICE -- GST Applicable

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	6,247.5	0.0	0.0	(682.1)	0.0	0.0	1,008.3	2,440.5	3,480.7	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	1,733.3	0.0	0.0	(189.2)	0.0	0.0	279.8	677.1	965.7	0.0
	- WBT	859.9	0.0	0.0	(93.9)	0.0	0.0	138.8	335.9	479.1	0.0
RATE 6	- SYSTEM SALES	509.9	0.0	0.0	(428.4)	0.0	0.0	267.9	478.3	192.1	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	408.7	0.0	0.0	(343.4)	0.0	0.0	214.7	383.3	154.0	0.0
	- WBT	211.4	0.0	0.0	(177.6)	0.0	0.0	111.1	198.3	79.7	0.0
RATE 9	- SYSTEM SALES	0.9	0.0	0.0	(0.2)	0.0	0.0	1.1	0.0	0.1	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	0.1	0.0	0.0	(0.0)	0.0	0.0	0.1	0.0	0.0	0.0
	- WBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	20.0	0.0	0.0	(1.1)	0.0	0.0	0.7	20.3	0.0	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	49.8	0.0	0.0	(2.6)	0.0	0.0	1.6	50.7	0.1	0.0
	- WBT	23.8	0.0	0.0	(1.3)	0.0	0.0	0.8	24.3	0.0	0.0
RATE 110	- SYSTEM SALES	147.1	0.0	0.0	(15.1)	0.0	0.0	2.9	159.3	0.1	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	905.6	0.0	0.0	(93.0)	0.0	0.0	17.9	980.3	0.4	0.0
	- WBT	145.1	0.0	0.0	(14.9)	0.0	0.0	2.9	157.1	0.1	0.0
RATE 115	- SYSTEM SALES	0.0	0.0	0.0	0.5	0.0	0.0	(0.0)	(0.4)	(0.0)	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(9.3)	0.0	0.0	(102.8)	0.0	0.0	10.8	82.7	0.1	0.0
	- WBT	(0.2)	0.0	0.0	(2.1)	0.0	0.0	0.2	1.7	0.0	0.0
RATE 135	- SYSTEM SALES	(4.8)	0.0	0.0	(1.2)	0.0	0.0	0.2	(3.7)	0.0	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(39.3)	0.0	0.0	(10.0)	0.0	0.0	1.2	(30.6)	0.1	0.0
	- WBT	(18.7)	0.0	0.0	(4.8)	0.0	0.0	0.6	(14.5)	0.0	0.0
RATE 145	- SYSTEM SALES	12.3	0.0	0.0	(4.8)	0.0	0.0	1.1	15.9	0.0	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	94.6	0.0	0.0	(37.2)	0.0	0.0	8.6	122.8	0.4	0.0
	- WBT	22.9	0.0	0.0	(9.0)	0.0	0.0	2.1	29.7	0.1	0.0
RATE 170	- SYSTEM SALES	18.5	0.0	0.0	(8.3)	0.0	0.0	0.6	26.1	0.0	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	277.2	0.0	0.0	(124.3)	0.0	0.0	8.9	392.5	0.1	0.0
	- WBT	5.4	0.0	0.0	(2.4)	0.0	0.0	0.2	7.6	0.0	0.0
RATE 200	- SYSTEM SALES	(21.7)	0.0	0.0	(25.6)	0.0	0.0	3.9	0.0	0.0	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(9.7)	0.0	0.0	(11.5)	0.0	0.0	1.8	0.0	0.0	0.0
	- WBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbundled Services:											
RATE 125		16.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0
RATE 300		1.2	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0
		11,607.6	0.0	0.0	(2,386.3)	0.0	0.0	2,105.8	6,535.4	5,352.7	0.0

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

ALLOCATION BY TYPE OF SERVICE -- HST Applicable

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL ($000)	SALES AND WBT ($000)	TOTAL SALES ($000)	TOTAL DELIVERIES ($000)	SPACE ($000)	DELIVE-RABILITY ($000)	DISTRIBUTION REV REQ (DRR) ($000)	DIRECT ($000)	NUMBER OF CUSTOMERS ($000)	RATE BASE ($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	(3,473.4)	(1,516.7)	0.0	2,513.4	(773.5)	(868.0)	(8,253.2)	3,260.1	1,723.6	440.9
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(542.9)	0.0	0.0	697.3	(214.6)	(240.8)	(2,289.8)	904.5	478.2	122.3
	- WBT	(478.1)	(208.8)	0.0	345.9	(106.5)	(119.5)	(1,135.9)	448.7	237.2	60.7
RATE 6	- SYSTEM SALES	(5,353.8)	(952.7)	0.0	1,578.7	(468.0)	(476.7)	(2,192.8)	(3,056.7)	95.1	119.4
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(3,527.5)	0.0	0.0	1,265.3	(375.1)	(382.1)	(1,757.5)	(2,450.0)	76.2	95.7
	- WBT	(2,219.9)	(395.0)	0.0	654.6	(194.1)	(197.7)	(909.3)	(1,267.5)	39.4	49.5
RATE 9	- SYSTEM SALES	(7.8)	(0.5)	0.0	0.8	(0.0)	(0.0)	(8.9)	0.0	0.0	0.8
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(1.0)	0.0	0.0	0.1	(0.0)	(0.0)	(1.2)	0.0	0.0	0.1
	- WBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	(4.8)	(2.3)	0.0	3.9	(1.0)	(1.2)	(5.4)	0.0	0.9	0.3
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(6.2)	0.0	0.0	9.7	(2.5)	(2.9)	(13.5)	0.0	2.2	0.7
	- WBT	(5.8)	(2.8)	0.0	4.6	(1.2)	(1.4)	(6.4)	0.0	1.1	0.4
RATE 110	- SYSTEM SALES	0.3	(33.6)	0.0	55.7	(0.3)	(2.0)	(23.7)	0.0	3.2	1.1
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	208.4	0.0	0.0	342.6	(2.1)	(12.1)	(146.2)	0.0	19.4	6.8
	- WBT	0.3	(33.1)	0.0	54.9	(0.3)	(1.9)	(23.4)	0.0	3.1	1.1
RATE 115	- SYSTEM SALES	(0.3)	1.0	0.0	(1.7)	0.0	0.0	0.4	0.0	(0.0)	(0.0)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	293.1	0.0	0.0	379.0	0.0	(4.5)	(88.5)	0.0	3.8	3.3
	- WBT	1.3	(4.7)	0.0	7.8	0.0	(0.1)	(1.8)	0.0	0.1	0.1
RATE 135	- SYSTEM SALES	0.9	(2.7)	0.0	4.5	0.0	0.0	(1.2)	0.0	0.3	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	29.7	0.0	0.0	36.8	0.0	0.0	(10.1)	0.0	2.7	0.3
	- WBT	3.6	(10.6)	0.0	17.5	0.0	0.0	(4.8)	0.0	1.3	0.1
RATE 145	- SYSTEM SALES	(2.5)	(10.7)	0.0	17.8	(2.9)	0.0	(9.2)	0.0	2.1	0.4
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	63.6	0.0	0.0	137.0	(22.2)	0.0	(70.8)	0.0	16.5	3.1
	- WBT	(4.6)	(20.0)	0.0	33.1	(5.4)	0.0	(17.1)	0.0	4.0	0.7
RATE 170	- SYSTEM SALES	4.5	(18.4)	0.0	30.5	(3.3)	0.0	(4.8)	0.0	0.3	0.2
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	343.6	0.0	0.0	458.0	(49.6)	0.0	(72.5)	0.0	4.6	3.2
	- WBT	1.3	(5.3)	0.0	8.9	(1.0)	0.0	(1.4)	0.0	0.1	0.1
RATE 200	- SYSTEM SALES	(32.0)	(56.9)	0.0	94.3	(23.6)	(15.5)	(31.9)	0.0	0.1	1.6
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	11.2	0.0	0.0	42.4	(10.6)	(7.0)	(14.3)	0.0	0.0	0.7
	- WBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbundled Services:											
RATE 125		(45.3)	0.0	0.0	0.0	0.0	0.0	(131.0)	0.0	79.4	6.3
RATE 300		(7.9)	0.0	0.0	0.0	0.0	0.0	(9.6)	0.0	1.1	0.6
		(14,751.9)	(3,273.9)	0.0	8,793.6	(2,257.9)	(2,333.4)	(17,236.1)	(2,160.9)	2,796.2	920.4

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

UNIT RATE AND TYPE OF SERVICE -- GST Applicable

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE
		($¢/m^3$)	($¢/m^3$)	($¢/m^3$)	($¢/m^3$)	($¢/m^3$)	($¢/m^3$)	($¢/m^3$)	($¢/m^3$)	($¢/m^3$)	($¢/m^3$)
Bundled Services:											
RATE 1	- SYSTEM SALES	0.2003	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0323	0.0782	0.1116	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.2003	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0323	0.0782	0.1116	0.0000
	- WESTERN T-SERVICE	0.2003	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0323	0.0782	0.1116	0.0000
RATE 6	- SYSTEM SALES	0.0260	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0137	0.0244	0.0098	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0260	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0137	0.0244	0.0098	0.0000
	- WESTERN T-SERVICE	0.0260	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0137	0.0244	0.0098	0.0000
RATE 9	- SYSTEM SALES	0.0881	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.1048	0.0000	0.0052	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0881	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.1048	0.0000	0.0052	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.4142	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0137	0.4219	0.0004	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.4142	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0137	0.4219	0.0004	0.0000
	- WESTERN T-SERVICE	0.4142	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0137	0.4219	0.0004	0.0000
RATE 110	- SYSTEM SALES	0.2130	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0042	0.2306	0.0001	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.2130	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0042	0.2306	0.0001	0.0000
	- WESTERN T-SERVICE	0.2130	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0042	0.2306	0.0001	0.0000
RATE 115	- SYSTEM SALES	(0.0020)	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0023	0.0176	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0020)	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0023	0.0176	0.0000	0.0000
	- WESTERN T-SERVICE	(0.0020)	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0023	0.0176	0.0000	0.0000
RATE 135	- SYSTEM SALES	(0.0859)	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0027	(0.0669)	0.0001	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0859)	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0027	(0.0669)	0.0001	0.0000
	- WESTERN T-SERVICE	(0.0859)	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0027	(0.0669)	0.0001	0.0000
RATE 145	- SYSTEM SALES	0.0556	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0051	0.0722	0.0002	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0556	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0051	0.0722	0.0002	0.0000
	- WESTERN T-SERVICE	0.0556	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0051	0.0722	0.0002	0.0000
RATE 170	- SYSTEM SALES	0.0488	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0016	0.0691	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0488	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0016	0.0691	0.0000	0.0000
	- WESTERN T-SERVICE	0.0488	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0016	0.0691	0.0000	0.0000
RATE 200	- SYSTEM SALES	(0.0185)	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0033	0.0000	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0185)	0.0000	0.0000	(0.0219)	0.0000	0.0000	0.0033	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services:											
RATE 125	- ALL	0.2373	0.0000	0.0000	0.0000	0.0000	0.0000	0.2373	0.0000	0.0000	0.0000
RATE 300	- ALL	1.3584	0.0000	0.0000	0.0000	0.0000	0.0000	1.3584	0.0000	0.0000	0.0000

Notes:
* Unit Rates derived based on 2010 actual volumes

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

UNIT RATE AND TYPE OF SERVICE – HST Applicable

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	NUMBER OF CUSTOMERS
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	($000/user)
Bundled Services:												
RATE 1	- SYSTEM SALES	(0.1114)	(0.0486)	0.0000	0.0806	(0.0248)	(0.0278)	(0.2646)	0.1045	0.0553	0.0141	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0627)	0.0000	0.0000	0.0806	(0.0248)	(0.0278)	(0.2646)	0.1045	0.0553	0.0141	0.0000
	- WESTERN T-SERVICE	(0.1114)	(0.0486)	0.0000	0.0806	(0.0248)	(0.0278)	(0.2646)	0.1045	0.0553	0.0141	0.0000
RATE 6	- SYSTEM SALES	(0.2733)	(0.0486)	0.0000	0.0806	(0.0239)	(0.0243)	(0.1119)	(0.1560)	0.0049	0.0061	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.2246)	0.0000	0.0000	0.0806	(0.0239)	(0.0243)	(0.1119)	(0.1560)	0.0049	0.0061	0.0000
	- WESTERN T-SERVICE	(0.2733)	(0.0486)	0.0000	0.0806	(0.0239)	(0.0243)	(0.1119)	(0.1560)	0.0049	0.0061	0.0000
RATE 9	- SYSTEM SALES	(0.7500)	(0.0486)	0.0000	0.0806	(0.0032)	(0.0009)	(0.8575)	0.0000	0.0029	0.0766	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.7014)	0.0000	0.0000	0.0806	(0.0032)	(0.0009)	(0.8575)	0.0000	0.0029	0.0766	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	(0.1001)	(0.0486)	0.0000	0.0806	(0.0206)	(0.0243)	(0.1119)	0.0000	0.0187	0.0061	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0515)	0.0000	0.0000	0.0806	(0.0206)	(0.0243)	(0.1119)	0.0000	0.0187	0.0061	0.0000
	- WESTERN T-SERVICE	(0.1001)	(0.0486)	0.0000	0.0806	(0.0206)	(0.0243)	(0.1119)	0.0000	0.0187	0.0061	0.0000
RATE 110	- SYSTEM SALES	0.0004	(0.0486)	0.0000	0.0806	(0.0005)	(0.0028)	(0.0344)	0.0000	0.0046	0.0016	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0490	0.0000	0.0000	0.0806	(0.0005)	(0.0028)	(0.0344)	0.0000	0.0046	0.0016	0.0000
	- WESTERN T-SERVICE	0.0004	(0.0486)	0.0000	0.0806	(0.0005)	(0.0028)	(0.0344)	0.0000	0.0046	0.0016	0.0000
RATE 115	- SYSTEM SALES	0.0137	(0.0486)	0.0000	0.0806	0.0000	(0.0010)	(0.0188)	0.0000	0.0008	0.0007	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0623	0.0000	0.0000	0.0806	0.0000	(0.0010)	(0.0188)	0.0000	0.0008	0.0007	0.0000
	- WESTERN T-SERVICE	0.0137	(0.0486)	0.0000	0.0806	0.0000	(0.0010)	(0.0188)	0.0000	0.0008	0.0007	0.0000
RATE 135	- SYSTEM SALES	0.0164	(0.0486)	0.0000	0.0806	0.0000	0.0000	(0.0221)	0.0000	0.0059	0.0006	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0650	0.0000	0.0000	0.0806	0.0000	0.0000	(0.0221)	0.0000	0.0059	0.0006	0.0000
	- WESTERN T-SERVICE	0.0164	(0.0486)	0.0000	0.0806	0.0000	0.0000	(0.0221)	0.0000	0.0059	0.0006	0.0000
RATE 145	- SYSTEM SALES	(0.0112)	(0.0486)	0.0000	0.0806	(0.0130)	0.0000	(0.0416)	0.0000	0.0097	0.0018	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0374	0.0000	0.0000	0.0806	(0.0130)	0.0000	(0.0416)	0.0000	0.0097	0.0018	0.0000
	- WESTERN T-SERVICE	(0.0112)	(0.0486)	0.0000	0.0806	(0.0130)	0.0000	(0.0416)	0.0000	0.0097	0.0018	0.0000
RATE 170	- SYSTEM SALES	0.0118	(0.0486)	0.0000	0.0806	(0.0087)	0.0000	(0.0128)	0.0000	0.0008	0.0006	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0605	0.0000	0.0000	0.0806	(0.0087)	0.0000	(0.0128)	0.0000	0.0008	0.0006	0.0000
	- WESTERN T-SERVICE	0.0118	(0.0486)	0.0000	0.0806	(0.0087)	0.0000	(0.0128)	0.0000	0.0008	0.0006	0.0000
RATE 200	- SYSTEM SALES	(0.0273)	(0.0486)	0.0000	0.0806	(0.0202)	(0.0132)	(0.0273)	0.0000	0.0001	0.0014	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0213	0.0000	0.0000	0.0806	(0.0202)	(0.0132)	(0.0273)	0.0000	0.0001	0.0014	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services:												
RATE 125	- All	(1.8415)	0.0000	0.0000	0.0000	0.0000	0.0000	(1.9422)	0.0000	0.0071	0.0936	0.0000
	- Customer-specific **											26.3000
RATE 300	- All	(9.1647)	0.0000	0.0000	0.0000	0.0000	0.0000	(11.1189)	0.0000	1.2383	0.7159	0.0000

Notes:
* Unit Rates derived based on 2010 actual volumes
** The Company incurred $78.9 k in additional staffing costs in 2010 associated with the additional upstream (such as FT-SN) nomination windows for unbundled customers. As specified in the NGEIR Settlement Agreement (EB-2005-0551 Ex S T1 S1 p13), the costs are to be recovered from the parties who availed of the service. Three customers on Rate 125 utilized the additional nomination windows in 2010 and the costs were allocated equally among the three customers.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

Enbridge Gas Distribution Inc.
2010 Deferral and Variance Account Clearing

Bill Adjustment in July 2011 for Typical Customers

Item No.	Col. 1	Col. 2		Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
				Unit Rates			Bill Adjustment		
	GENERAL SERVICE	Annual Volume m³		Sales cents/m³	Ontario TS cents/m³	Western TS cents/m³	Sales Customers $	Ontario TS Customers $	Western TS Customers $
1.1	**RATE 1 RESIDENTIAL**								
1.2	Heating & Water Heating	3,064	GST	0.2003	0.2003	0.2003	6	6	6
1.3			HST	(0.1114)	(0.0627)	(0.1114)	(3)	(2)	(3)
1.4							3	4	3
2.1	**RATE 6 COMMERCIAL**								
2.2	General Use	43,285	GST	0.0260	0.0260	0.0260	11	11	11
2.3			HST	(0.2733)	(0.2246)	(0.2733)	(118)	(97)	(118)
2.4							(107)	(86)	(107)
	CONTRACT SERVICE								
3.1	**RATE 100**								
3.2	Industrial - small size	339,188	GST	0.4142	0.4142	0.4142	1,405	1,405	1,405
3.3			HST	(0.1001)	(0.0515)	(0.1001)	(340)	(175)	(340)
3.4							1,065	1,230	1,065
4.1	**RATE 110**								
4.2	Industrial - small size, 50% LF	598,568	GST	0.2130	0.2130	0.2130	1,275	1,275	1,275
4.3			HST	0.0004	0.0490	0.0004	2	293	2
4.4							1,277	1,568	1,277
4.5	Industrial - avg. size, 75% LF	9,976,120	GST	0.2130	0.2130	0.2130	21,249	21,249	21,249
4.6			HST	0.0004	0.0490	0.0004	39	4,890	39
4.7							21,288	26,139	21,288
5.1	**RATE 115**								
5.2	Industrial - small size, 80% LF	4,471,609	GST	(0.0020)	(0.0020)	(0.0020)	(88)	(88)	(88)
5.3			HST	0.0137	0.0623	0.0137	612	2,786	612
5.4							524	2,698	524
6.1	**RATE 135**								
6.2	Industrial - Seasonal Firm	598,567	GST	(0.0859)	(0.0859)	(0.0859)	(514)	(514)	(514)
6.3			HST	0.0164	0.0650	0.0164	98	389	98
6.4							(416)	(125)	(416)
7.1	**RATE 145**								
7.2	Commercial - small size	598,568	GST	0.0556	0.0556	0.0556	333	333	333
7.3			HST	(0.0112)	0.0374	(0.0112)	(67)	224	(67)
7.4							266	557	266
8.1	**RATE 170**								
8.2	Industrial - avg. size, 75% LF	9,976,120	GST	0.0488	0.0488	0.0488	4,866	4,866	4,866
8.3			HST	0.0118	0.0605	0.0118	1,180	6,031	1,180
8.4							6,046	10,897	6,046

Notes:
Col. 6 = Col. 2 x Col. 3
Col. 7 = Col. 2 x Col. 4
Col. 8 = Col. 2 x Col. 5

ENBRIDGE GAS DISTRIBUTION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2010

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE GAS DISTRIBUTION INC.

Financial Reporting
Management is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are not officers or employees of the Company, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Audit, Finance & Risk Committee meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit, Finance & Risk Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the Company's Board of Directors, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

Janet A. Holder
President, Gas Distribution

(Signed)

Narinder K. Kishinchandani
Vice President, Finance

February 18, 2011

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
North American Centre
5700 Yonge Street, Suite 1900
North York, Ontario
Canada M2M 4K7
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Independent Auditor's Report

To the Shareholders of Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2010 and 2009 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes including a summary of significant accounting policies.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2010 and 2009 and the results of their operations and their cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Accountants, Licensed Public Accountants
February 18, 2011
Toronto Ontario

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Gas Commodity and Distribution Revenue	**1,977**	2,346
Transportation of Gas for Customers	**390**	449
	2,367	2,795
Gas Commodity and Distribution Costs Excluding Depreciation *(Note 19)*	**(1,372)**	(1,770)
Gas Distribution Margin	**995**	1,025
Other Revenue	**108**	108
	1,103	1,133
Expenses		
Operating and administrative *(Note 19)*	**393**	385
Depreciation and amortization	**270**	254
Municipal and other taxes	**44**	49
Earnings sharing *(Note 3)*	**19**	19
	726	707
	377	426
Affiliate Financing Income *(Note 19)*	**63**	63
Interest Expense *(Notes 9 and 19)*	**(186)**	(190)
	254	299
Income Taxes *(Note 16)*		
Current	**(59)**	(51)
Future	**(2)**	(27)
	(61)	(78)
Earnings	**193**	221
Preferred Share Dividends	**(2)**	(3)
Earnings Applicable to the Common Shareholder	**191**	218

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Earnings	**193**	221
Other Comprehensive (Loss)/Income		
Change in fair value of cash flow hedges, net of tax	**(13)**	1
Reclassification to earnings of realized (losses)/gains on cash flow hedges, net of tax	**(2)**	2
Change in foreign currency translation adjustment	**(1)**	(3)
Other Comprehensive Loss	**(16)**	-
Comprehensive Income	**177**	221

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Preferred Shares *(Note 11)*	**100**	100
Common Shares *(Note 11)*	**1,071**	1,071
Contributed Surplus	**202**	202
Retained Earnings		
Balance at beginning of year	**596**	566
Earnings applicable to the common shareholder	**191**	218
Common share dividends declared	**(215)**	(188)
Balance at End of Year	**572**	596
Accumulated Other Comprehensive Loss		
Balance at beginning of year	**(2)**	(2)
Other comprehensive loss	**(16)**	-
Balance at End of Year	**(18)**	(2)
Total Shareholders' Equity	**1,927**	1,967

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Operating Activities		
Earnings	**193**	221
Depreciation and amortization	**270**	254
Future income taxes	**2**	27
Other	**2**	2
Changes in operating assets and liabilities *(Note 18)*	**31**	467
Settlement recoverable *(Note 3)*	**5**	-
	503	971
Investing Activities		
Additions to property, plant and equipment	**(345)**	(309)
Additions to intangible assets	**(20)**	(61)
Change in construction payable	**-**	(11)
Other	**-**	(3)
	(365)	(384)
Financing Activities		
Net change in short-term borrowings	**(182)**	(367)
Issue of short-term note payable to affiliate company *(Note 19)*	**2**	6
Repayment of short-term note payable to affiliate company *(Note 19)*	**(3)**	(6)
Debenture and term note issues	**402**	-
Debenture and term note repayments	**(150)**	(102)
Preferred share dividends	**(2)**	(4)
Common share dividends	**(208)**	(181)
Other	**(2)**	(1)
	(143)	(655)
Increase in Bank Overdraft	**(5)**	(68)
(Bank Overdraft)/Cash and Cash Equivalents at Beginning of Year	**(13)**	55
Bank Overdraft at End of Year	**(18)**	(13)
Supplementary Cash Flow Information		
Income taxes paid	**59**	113
Interest paid *(Note 9)*	**185**	187

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2010**	2009
(millions of Canadian dollars)		
Assets		
Current Assets		
Accounts receivable and other *(Notes 4 and 19)*	**802**	801
Gas inventories	**400**	396
	1,202	1,197
Property, Plant and Equipment, net *(Note 5)*	**4,458**	4,290
Investment in Affiliate Company *(Note 19)*	**825**	825
Deferred Amounts and Other Assets *(Note 6)*	**487**	487
Intangible Assets *(Note 7)*	**167**	179
	7,139	6,978
Liabilities and Shareholders' Equity		
Current Liabilities		
Bank overdraft	**18**	13
Short-term borrowings *(Note 9)*	**332**	515
Accounts payable and other *(Notes 8 and 19)*	**836**	781
Current maturities of long-term debt *(Note 9)*	**150**	150
Future income taxes *(Note 16)*	**5**	5
	1,341	1,464
Long-Term Debt *(Note 9)*	**2,267**	2,015
Other Long-Term Liabilities *(Note 10)*	**1,058**	972
Future Income Taxes *(Note 16)*	**171**	185
Loans from Affiliate Company *(Notes 9 and 19)*	**375**	375
	5,212	5,011
Shareholders' Equity		
Share capital		
Preferred shares *(Note 11)*	**100**	100
Common shares *(Note 11)*	**1,071**	1,071
Contributed surplus	**202**	202
Retained earnings	**572**	596
Accumulated other comprehensive loss	**(18)**	(2)
	1,927	1,967
Commitments and Contingencies *(Notes 19 and 20)*		
	7,139	6,978

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

(Signed)

Janet A. Holder
President, Gas Distribution

(Signed)

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 3)*; allowance for doubtful accounts *(Note 4)*; depreciation rates and carrying values of property, plant and equipment *(Note 5)*; amortization rates of intangible assets *(Note 7)*; fair values of financial instruments *(Notes 13 and 14)*; income taxes *(Note 16)*; post-employment benefits *(Note 17);* contingencies *(Note 20);* and fair value of asset retirement obligations. Actual results could differ from these estimates.

BASIS OF PRESENTATION
The consolidated financial statements include the accounts of the Company and its subsidiaries. Investments are accounted for according to their classification (see Financial Instruments).

REGULATION
The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and rate-making and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

REVENUE RECOGNITION
The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

FINANCIAL INSTRUMENTS
The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, other financial liabilities or derivatives in qualifying hedging relationships. The Company has not classified any financial assets or liabilities as held to maturity.

Held for Trading
Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings. The Company has classified Cash and Cash Equivalents and Bank Overdraft as held for trading.

Available for Sale
The Company classifies its investment in the preferred shares of IPL System Inc. as an available for sale financial asset. Such instruments are periodically created by the Company and its affiliated companies to meet the current and future financing requirements of either the Company or its affiliated companies and no external market for the instrument exists. As this investment originated in a related party transaction and has no quoted market price in an active market, it is carried at cost and a fair value has not been determined. Dividends received from this investment are recognized in earnings when the right to receive payment is established *(Note 19)*.

Loans and Receivables
Loans and receivables, which include Accounts Receivable and Other, are initially recognized at fair value and subsequently measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

Other Financial Liabilities
Other financial liabilities are measured at amortized cost using the effective interest rate method and include Short-Term Borrowings, Accounts Payable and Other, Long-Term Debt and Loans from Affiliate Company.

Derivatives in Qualifying Hedging Relationships
The Company uses derivative financial instruments to manage changes in natural gas prices and interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges.

Cash Flow Hedges
The Company uses cash flow hedges to manage changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other Comprehensive Income (OCI) and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

The majority of St. Lawrence's derivatives relate to the management of natural gas prices. Given that St. Lawrence is subject to rate regulation, the effective portion of changes in the fair value of these derivatives is deferred as an asset or liability until they are settled and an offsetting asset or liability is recorded on behalf of customers. Upon settlement, the recognized gain or loss is recorded as a regulatory asset or liability and is collected from or refunded to customers in subsequent period rates.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

INCOME TAXES
The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

FOREIGN CURRENCY TRANSLATION

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. This operation is self-sustaining and is translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of this operation are included in the foreign currency translation adjustment component of Accumulated Other Comprehensive Loss (AOCL).

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of ninety days or less upon issuance.

GAS INVENTORIES

Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred for future collection or refund by the Company to the customers, as approved by the Regulators. Actual cost of natural gas for St. Lawrence includes the effect of natural gas price risk management activities.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2010, $102 million of natural gas was held on behalf of transportation service customers (December 31, 2009 - $164 million). These transactions have no impact on the Company's consolidated earnings, cash flows or financial position.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost, including associated operating costs and an allowance for interest during construction at current arm's length interest rates.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation.

Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved the by Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets include costs that the Regulators have permitted, or are expected to permit, to be recovered through future rates, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS

Intangible assets consist primarily of the Customer Information System (CIS) and software costs, which are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) associated with the retirement of long-lived assets would be measured at fair value and recognized as Other Long-Term Liabilities in the period in which they could be reasonably determined. The fair value would approximate the cost a third party would charge to perform the tasks necessary to retire such assets and would be recognized at the present value of expected future cash flows. AROs would be added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability would be accreted over time through charges to earnings and would be reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

It is not possible to make a reasonable estimate of AROs for the Company due to the indeterminate timing of the asset retirements.

POST-EMPLOYMENT BENEFITS

The Company maintains non-contributory pension plans that provide defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants.

The Company's post-employment benefits are determined as follows:

- The cost of pensions and OPEB earned by employees is actuarially determined using the projected benefit method pro-rated on service and management's best estimate of the expected plan investment performance, salary escalation, retirement ages of employees and expected health-care and insurance costs.
- Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific asset mix within the pension plan. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.
- The excess of the cumulative unrecognized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets is amortized over the expected average remaining service lives of employees.
- Pension costs under the defined benefit pension plans have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages. Adjustments arising from plan amendments, actuarial gains and losses, and changes to assumptions are amortized over the expected average remaining service lives of the employees.
- The transitional asset and obligation is amortized over the expected average remaining service lives of employees. The transitional asset relates to the pension plans and is the fair value of the plan assets less the accrued benefit obligation at October 1, 2000, amortized over 13 years. The transitional obligation relates to OPEB and is equal to the accrued benefit obligation at October 1, 2000, amortized over 15 years.

The regulated utility operations of the Company recover pension and OPEB expense based on the amounts paid. This is in accordance with the methodology accepted by the Regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension and OPEB regulatory liability and asset has been recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

COMPARATIVE AMOUNTS

Certain comparative amounts have been reclassified to conform with the current year's consolidated financial statement presentation.

2. CHANGES IN ACCOUNTING POLICIES

FUTURE ACCOUNTING POLICY CHANGES

International Financial Reporting Standards

First-time adoption of Part I – International Financial Reporting Standards (Part I) of the Canadian Institute of Chartered Accountants (CICA) Handbook is mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and it will continue to present its financial statements in accordance with Part V – Pre-changeover Accounting Standards of the CICA Handbook during the 2011 deferral period.

Business Combinations
CICA Handbook Section 1582, *Business Combinations*, replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. The adoption of this standard will impact the Company's accounting treatment of any future business combinations occurring on or after January 1, 2011.

Consolidated Financial Statements and Non-Controlling Interests
The CICA issued Handbook Sections 1601, *Consolidated Financial Statements* and 1602, *Non-controlling Interests,* which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards is not expected to have a material impact to the Company's consolidated earnings or cash flows. The revised standards are effective January 1, 2011.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, "Enbridge Gas Distribution" refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas "St. Lawrence" refers specifically to St. Lawrence Gas Company, Inc.

RATE APPROVAL
Enbridge Gas Distribution's annual rates are currently set using a revenue per customer cap Incentive Regulation (IR) methodology. This IR methodology adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The cost of natural gas is passed on to customers as a flow-through.

St. Lawrence's rates for each year are set using a Cost of Service (COS) methodology that allows the revenues to be set to recover forecast costs and to earn a rate of return on common equity. Forecast costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, municipal taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under COS, it is the responsibility of St. Lawrence to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken. The cost of natural gas is passed on to customers as a flow-through.

APPROVED RATES

Enbridge Gas Distribution
Enbridge Gas Distribution's after-tax rate of return on common equity embedded in rates was 8.39% for the year ended December 31, 2010 (2009 – 8.39%) based on a 36% (2009 – 36%) deemed common equity component of capital for regulatory purposes.

To align the interests of customers with the Company's common shareholder, an earnings sharing mechanism forms part of the Settlement Agreement (the Settlement) with customer representatives approved by the OEB in February 2008. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive). To the extent the actual utility return on the approved equity level represented by normalized earnings (i.e., excluding the effects of weather) (ROE) exceeds the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings are shared with customers. The common shareholder retains the first 100 basis points of ROE above the NROE, while earnings represented by the ROE in excess of 100 basis points above the NROE are shared equally with customers.

St. Lawrence
St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.50% for the year ended December 31, 2010 (2009 – 8.89%) based on a 50% (2009 – 51.5%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 11.0% (2009 – 9.6%) are shared equally with customers. The calculation of such earnings is cumulative over the three-year period commencing

January 1, 2010 and ending December 31, 2012, and resulted in no sharing impact as at December 31, 2010 (2009 - $nil).

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, the Company generally would not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Long-term regulatory liabilities are recorded in Other Long-Term Liabilities and current regulatory liabilities are recorded in Accounts Payable and Other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ from those recorded.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2010**	2009	Consolidated Statements of Financial Position Location**	Estimated Recovery/ Settlement Period (years)	Earnings Impact[1] **2010**	Earnings Impact[1] 2009
(millions of Canadian dollars)						
Regulatory Assets/(Liabilities)						
Enbridge Gas Distribution						
Future income taxes [2]	**164**	174	DA/OLTL	*	**(7)**	-
OPEB [3]	**68**	62	DA	*	**1**	4
Unaccounted for gas variance [4]	**18**	10	AR	1	**5**	6
Settlement recoverable [5]	**15**	20	AR/DA	2	**(3)**	-
Shared Savings Mechanism [6]	**11**	14	AR	*	**-**	-
Average use true-up variance [7]	**4**	3	AR	*	**1**	4
Deferred rate hearing costs [8]	**3**	6	AR/DA	2	**(2)**	-
Future removal and site restoration reserves [9]	**(753)**	(692)	OLTL	*	**-**	-
Pension plans [10]	**(222)**	(205)	OLTL	*	**6**	(6)
Purchased gas variance [11]	**(144)**	(227)	AP	1	**-**	-
Earnings sharing deferral [12]	**(38)**	(25)	AP	1	**-**	-
Transactional services deferral [13]	**(14)**	(14)	AP	1	**-**	-
Other regulatory assets and liabilities	**10**	10	***	*	**-**	(3)
	(878)	(864)			**1**	5
St. Lawrence						
Other regulatory assets and liabilities	**3**	(2)	***	*	**3**	(1)
	3	(2)			**3**	(1)
	(875)	(866)			**4**	4

* Refer to the footnote for details.
** AR – Accounts Receivable and Other
AP – Accounts Payable and Other
DA – Deferred Amounts and Other Assets
OLTL – Other Long-Term Liabilities
*** Dependent on the nature of the item.

1. The increase/(decrease) in the Company's after-tax reported earnings as a result of the rate regulation recognition of the item, excluding any additional earnings sharing impact. This includes the impact from recovery or refund, during the current year, of items outstanding at the end of the prior year.

2. The future income taxes balance represents the regulatory offset to future income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on future temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.

3. The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover OPEB expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and OPEB expense would be charged to earnings based on the accrual basis of accounting.

4. Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation, this variance would be included in earnings in the year incurred.

5. Settlement recoverable deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts are being recovered from customers over a five-year period, which commenced in 2008. In the absence of rate regulation, these costs would be expensed as incurred.

6. Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.

7. Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual normalized average use for general service customers. The amount will be recovered

from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, the variance would be included in earnings in the year incurred.

8. Deferred rate hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation, these costs would be expensed as incurred.

9. Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

10. The pension plans' balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover pension expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would be charged to earnings based on the accrual basis of accounting.

11. Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to customers in the following year. In the absence of rate regulation, the actual cost of natural gas would be included in commodity costs and commodity revenue would be adjusted by an equal and offsetting amount as the right to collect the revenue has been established.

12. Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement. The earnings sharing is payable to customers and represents 50% of normalized earnings (i.e., excluding the effects of weather) represented by the ROE in excess of 100 basis points above the NROE. The December 31, 2010 balance relates to the years ended December 31, 2010 and 2009. The December 31, 2009 balance relates to the years ended December 31, 2009 and 2008. There would be no change in the treatment of this item in the absence of rate regulation.

13. Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue

To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

Operating Cost Capitalization

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs may be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2010, costs relating to this services contract of $124 million (2009 - $112 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment

In the absence of rate regulation, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2010, the net book value of these costs was $111 million (2009 - $124 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. In the absence of rate regulation, the actual price of natural gas purchased would be recorded in gas inventories.

Included in gas inventories at December 31, 2010 is $43 million (2009 - $41 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred.

Depreciation

In the absence of rate regulation, depreciation rates would not have included a provision for future removal and site restoration costs.

4. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2010**	2009
(millions of Canadian dollars)		
Trade receivables	**422**	391
Unbilled revenues	**231**	222
Agent billing and collection receivable	**86**	105
Regulatory assets *(Note 3)*	**61**	67
Due from affiliates *(Note 19)*	**11**	15
Taxes receivable	**14**	33
Prepaid expenses	**5**	8
Other	**23**	17
Allowance for doubtful accounts	**(51)**	(57)
	802	801

5. PROPERTY, PLANT AND EQUIPMENT

December 31, 2010	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Gas mains	**4.2%**	**2,505**	**484**	**2,021**
Gas services	**4.6%**	**2,036**	**628**	**1,408**
Regulating and metering equipment	**3.8%**	**691**	**224**	**467**
Storage	**2.8%**	**240**	**79**	**161**
Land and right-of-way	**2.6%**	**77**	**29**	**48**
Computer technology	**19.8%**	**33**	**4**	**29**
Under construction	**-**	**66**	**-**	**66**
Other	**3.5%**	**259**	**76**	**183**
		5,907	**1,524**	**4,383**
Unregulated storage	**3.6%**	**52**	**2**	**50**
Construction materials inventory	**-**	**25**	**-**	**25**
		5,984	**1,526**	**4,458**

December 31, 2009	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Gas mains	4.2%	2,373	440	1,933
Gas services	4.4%	1,961	594	1,367
Regulating and metering equipment	3.7%	677	216	461
Storage	2.8%	228	73	155
Land and right-of-way	2.5%	68	27	41
Computer technology	19.5%	27	3	24
Under construction	-	71	-	71
Other	3.4%	247	79	168
		5,652	1,432	4,220
Unregulated storage	4.1%	48	1	47
Construction materials inventory	-	23	-	23
		5,723	1,433	4,290

Total depreciation expense, including amounts collected for future removal and site restoration costs, for property, plant and equipment was $238 million for the year ended December 31, 2010 (2009 - $225 million).

6. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2010**	2009
(millions of Canadian dollars)		
Regulatory assets *(Note 3)*	**252**	259
Pension asset *(Note 17)*	**222**	205
Long-term portion of derivative assets *(Note 14)*	**-**	4
Other	**13**	19
	487	487

7. INTANGIBLE ASSETS

December 31, 2010	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**20.1%**	**100**	**44**	**56**
CIS	**10.0%**	**127**	**16**	**111**
		227	**60**	**167**

December 31, 2009	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	20.5%	107	52	55
CIS	10.5%	127	3	124
		234	55	179

Intangible assets include $9 million of work-in-progress for the year ended December 31, 2010 (2009 - $9 million). Total amortization expense for intangible assets was $32 million for the year ended December 31, 2010 (2009 - $29 million).

8. ACCOUNTS PAYABLE AND OTHER

December 31,	**2010**	2009
(millions of Canadian dollars)		
Operating accrued liabilities	**282**	240
Regulatory liabilities *(Note 3)*	**204**	295
Budget billing plan payable	**92**	64
Security deposits	**73**	57
Dividends payable	**54**	47
Trade payables	**43**	25
Taxes payable	**34**	9
Interest payable	**29**	29
Due to affiliates *(Note 19)*	**3**	4
Current derivative liabilities *(Note 14)*	**1**	3
Other	**21**	8
	836	781

9. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2010**	2009
(millions of Canadian dollars)				
Debentures	10.46%	2011-2024	**235**	385
Medium-term notes	5.54%	2014-2050	**2,195**	1,795
Commercial paper and credit facility draws, net			**333**	508
Other			**6**	12
Deferred debt issue costs			**(20)**	(20)
Total Debt			**2,749**	2,680
Current Maturities			**(150)**	(150)
Short-Term Borrowings	1.13%		**(332)**	(515)
Long-Term Debt			**2,267**	2,015
Loans from Affiliate Company			**375**	375

Debenture and term note maturities for the years ending December 31, 2011 through 2015 are $150 million, $nil, $nil, $400 million, and $nil, respectively. The Company’s debentures and term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2011 through 2015 are $138 million, $130 million, $130 million, $124 million and $109 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Debentures and medium-term notes	**149**	151
Loans from affiliate company *(Note 19)*	**27**	27
Commercial paper and credit facility draws	**2**	4
Other interest and finance costs	**11**	14
Capitalized	**(3)**	(6)
	186	190

In 2010, total interest paid to third parties was $158 million (2009 - $160 million) and total interest paid to affiliated companies was $27 million (2009 - $27 million).

CREDIT FACILITIES

In 2010, the Company elected to reduce its committed credit facilities and commercial paper program limit by $100 million. The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The Company has the option, at its discretion, to extend the maturity date of the committed lines of credit for an additional year.

December 31, 2010	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc.	**700**	**325**	**375**
St. Lawrence Gas Company, Inc.	**12**	**8**	**4**
Total Credit Facilities	**712**	**333**	**379**

1. Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

Credit facilities carried a weighted average standby fee of 0.60% per annum from January to July 2010 and 0.38% per annum from August to December 2010 on the unused portion and draws bear interest at market rates.

10. OTHER LONG-TERM LIABILITIES

December 31,	**2010**	2009
(millions of Canadian dollars)		
Regulatory liabilities *(Note 3)*	**984**	897
OPEB liabilities *(Note 17)*	**71**	70
Pension liability *(Note 17)*	**3**	3
Other	**-**	2
	1,058	972

11. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preferred shares.

COMMON SHARES

December 31,	**2010**		2009	
	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)				
Balance at beginning of year	**141**	**1,071**	141	1,071
Common shares issued	**-**	**-**	-	-
Balance at End of Year	**141**	**1,071**	141	1,071

PREFERRED SHARES

December 31, 2010 and 2009	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preferred shares in millions)			
Group 1	**0.2**	**Nil**	**-**
Group 2, Series A - C, Cumulative Redeemable Retractable	**6**	**Nil**	**-**
Group 2, Series D, Cumulative Redeemable Convertible	**4**	**Nil**	**-**
Group 3, Series A - C, Cumulative Redeemable Retractable	**6**	**Nil**	**-**
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	**4**	**4**	**100**
Group 4	**10**	**Nil**	**-**
Group 5	**10**	**Nil**	**-**
			100

Cumulative cash dividends on the Group 3, Series D preferred shares were payable at a fixed yield rate of 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preferred shares can be converted, at the holder's option, into Group 2, Series D preferred shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preferred shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preferred shares can also be converted into Group 3, Series D preferred shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

12. STOCK OPTION AND STOCK UNIT PLANS

Certain employees and senior officers of the Company are granted stock-based compensation from Enbridge through its three long-term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

During the year ended December 31, 2010, 180,500 stock options (2009 – 244,350 options) were issued to employees of the Company. The stock options were issued at a weighted average exercise price of $46.59 in 2010 (2009 - $39.61) and a grant date fair value of $6.56 (2009 - $6.73).

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan that includes the Company's senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average common share price and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two, if Enbridge performs within the highest range of its performance targets. The 2008, 2009, and 2010 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's growth in earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

During the year ended December 31, 2010, 9,100 PSUs (2009 – 6,900) were issued to employees of the Company.

RESTRICTED STOCK UNITS

Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price multiplied by the units outstanding on the maturity date.

During the year ended December 31, 2010, Enbridge granted 58,750 RSUs (2009 – 61,800) to certain employees of the Company.

STOCK-BASED COMPENSATION EXPENSE

The Company is charged an expense for stock-based compensation which includes a direct charge for ISOs, PSUs and RSUs issued to employees of the Company and an allocation of such costs with respect to employees of Enbridge who provide services to the Company. For the year ended December 31, 2010, the direct charge totaled $6 million (2009 – $5 million) and the allocation totaled $5 million (2009 – $4 million). These costs are included in operating and administrative expenses.

13. RISK MANAGEMENT

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in interest rates, foreign exchange rates and natural gas prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt (commercial paper). Floating to fixed interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.8%.

At December 31, 2010, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have caused a $3 million increase (2009 - $15 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2010, and a $nil effect (2009 - $4 million decrease) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2010 assuming the variable rate debt outstanding had been outstanding for the entire period.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is $nil (2009 - $nil).

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Only St. Lawrence manages the exposure to natural gas price risk by entering into fixed price natural gas contracts. Other than St. Lawrence, the Company no longer manages natural gas price risk exposure, in compliance with the directive of the OEB. Fluctuations in natural gas prices are borne by the customers.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

December 31, 2010	2011	2012	2013	2014	2015	Thereafter
Natural gas *($10^6 m^3$)*	17	6	-	-	-	-
Interest rate contracts *(millions of Canadian dollars)*	279	111	-	-	-	-
Net Cash Flows	296	117	-	-	-	-

The Company does not have any credit-risk related contingent features associated with its derivative instruments.

The Company estimates that $3 million of AOCL related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. Any gains or losses from natural gas derivatives are borne by customers. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 24 months at December 31, 2010.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 19 and 20)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt which includes debentures and medium-term notes. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 9)* with a diversified group of banks and institutions which, if necessary, would enable the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2010. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt and loans from affiliate company *(Notes 9 and 19)*.

For the years ending December 31, 2011 through 2015, and thereafter, the Company has estimated that the following undiscounted cash flows will arise from its financial derivative instruments based on valuations at the balance sheet date:

	2011	2012	2013	2014	2015	Thereafter
(millions of Canadian dollars)						
Cash inflows	-	-	-	-	-	-
Cash outflows	(1)	-	-	-	-	-
Net Cash Flows	(1)	-	-	-	-	-

CREDIT RISK

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 14, Fair Value of Financial Instruments.

The change in the allowance for doubtful accounts in respect of accounts receivable is detailed below:

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Balance at beginning of year	**(57)**	(50)
Additional allowance	**(23)**	(29)
Amounts used and reversed	**29**	22
Balance at End of Year	**(51)**	(57)

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 21 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts.

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate. Under IR, these estimated costs recovered through distribution rates relate to the base year of the IR plan (2007) and are escalated by the approved formula during the IR term.

Entering into derivative financial instruments can also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements. At December 31, 2010, the Company has a maximum exposure to credit risk of $nil (2009 - $3 million) related to its derivative counterparties.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Accounts receivable and other	**-**	**-**	**722**	**-**	**-**	**80**	**802**	**722**
Investment in affiliate company	**-**	**825**	**-**	**-**	**-**	**-**	**825**	**N/A**
Deferred amounts and other assets	**-**	**-**	**-**	**-**	**-**	**487**	**487**	**-**
Liabilities								
Bank overdraft	**18**	**-**	**-**	**-**	**-**	**-**	**18**	**18**
Short-term borrowings	**-**	**-**	**-**	**332**	**-**	**-**	**332**	**332**
Accounts payable and other	**-**	**-**	**-**	**597**	**1**	**238**	**836**	**598**
Long-term debt	**-**	**-**	**-**	**2,417**	**-**	**-**	**2,417**	**2,775**
Loans from affiliate company[2]	**-**	**-**	**-**	**375**	**-**	**-**	**375**	**N/A**

December 31, 2009	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Accounts receivable and other	-	-	691	-	2	108	801	693
Investment in affiliate company	-	825	-	-	-	-	825	N/A
Deferred amounts and other assets	-	-	-	-	4	483	487	4
Liabilities								
Bank overdraft	13	-	-	-	-	-	13	13
Short-term borrowings	-	-	-	515	-	-	515	515
Accounts payable and other	-	-	-	474	3	304	781	477
Long-term debt	-	-	-	2,165	-	-	2,165	2,445
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

1 *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market (Note 19).*

2 *Loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined (Note 19).*

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

FAIR VALUE OF DERIVATIVES

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps and natural gas swaps for which observable inputs can be obtained.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates.

When possible the estimated fair value is based on quoted market prices, and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and the nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and natural gas) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

December 31, 2010	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets:				
Current derivative assets	**-**	**-**	**-**	**-**
Long-term derivative assets	**-**	**-**	**-**	**-**
Financial liabilities:				
Current derivative liabilities	**-**	**(1)**	**-**	**(1)**
Long-term derivative liabilities	**-**	**-**	**-**	**-**
Total Net Derivative Liability	**-**	**(1)**	**-**	**(1)**

December 31, 2009	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets:				
Current derivative assets	-	2	-	2
Long-term derivative assets	-	4	-	4
Financial liabilities:				
Current derivative liabilities	-	(3)	-	(3)
Long-term derivative liabilities	-	-	-	-
Total Net Derivative Asset	-	3	-	3

15. CAPITAL DISCLOSURES

The Company defines capital as shareholders’ equity (excluding AOCL), long-term debt (including intercompany debt, excluding transaction costs), short-term borrowings and bank overdraft less cash and cash equivalents.

The Company’s capital is calculated as follows:

December 31,	**2010**	2009
(millions of Canadian dollars)		
Bank overdraft	**18**	13
Short-term borrowings	**332**	515
Long-term debt (includes current portion)	**2,437**	2,185
Loans from affiliate company	**375**	375
Shareholders’ equity	**1,945**	1,969
Cash and cash equivalents	**-**	-
	5,107	5,057

The Company’s objectives when managing capital are to maintain flexibility among: enabling the business to operate at the highest efficiency while maintaining safety and reliability; providing liquidity for growth opportunities; maintaining a capital structure that is in alignment with the deemed equity ratio of 36%; and providing acceptable returns to the common shareholder. These objectives are primarily met through maintenance of an investment grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt and equity.

The Company manages its capital in light of changes in the economic and regulatory environment and the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to the common shareholder, issue new shares or issue new debt. Dividend payments are determined with the objective of maintaining a capital structure that is in alignment with the deemed equity ratio of 36%.

Due to the seasonal nature of the Company's business and continuing growth in the asset base, cash receipts do not typically match the Company's requirements for capital expenditures, dividends, long-term debt retirement and inventory replenishment. Generally, cash shortfalls are financed initially through the issuance of short-term debt. The Company maintains a balanced capital structure by periodically refinancing short-term debt with long-term debt.

The Company’s borrowings, whether debentures or medium-term notes, are unsecured. When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company’s trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as Canadian GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of debt issue costs and intercompany interest expense, less gains on asset dispositions divided by the annual interest requirements. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2010, the Company was in compliance with these covenants.

16. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Earnings before income taxes	**254**	299
Combined statutory income tax rate	**31.0%**	33.0%
Income taxes at statutory rate	**79**	99
Increase/(decrease) resulting from:		
Non-taxable dividend income from affiliated companies	**(19)**	(21)
Future income taxes related to regulated operations	**7**	-
Other	**(6)**	-
Income Taxes	**61**	78
Effective Income Tax Rate	**24%**	26%

The future income taxes recorded in current liabilities of $5 million (2009 - $5 million) arise primarily from temporary differences relating to regulatory deferral accounts.

At December 31, 2010, the Company had a future income tax liability of $164 million (2009 - $174 million) related to regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset to the extent that the future income tax liability is expected to be included in regulator-approved future rates and recovered from future customers.

17. POST-EMPLOYMENT BENEFITS

PENSION PLANS

The Company maintains a non-contributory basic pension plan that provides defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees. The management selected measurement date of December 31, 2010 was used to determine the plan assets and the accrued benefit obligation.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members’ years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuation and the next required actuarial valuation are as follows:

Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
December 31, 2009	December 31, 2012

The defined benefit pension plans' costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans
Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

Post-employment Benefits Other than Pensions
OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

DEFINED BENEFIT PLANS
The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plan using the accrual method.

	Pension Benefits		OPEB	
December 31,	**2010**	2009	**2010**	2009
(millions of Canadian dollars)				
Change in Accrued Benefit Obligation				
Benefit obligation at beginning of year	**588**	579	**81**	83
Service cost	**12**	13	**1**	1
Interest cost	**39**	39	**5**	6
Actuarial loss/(gain)[1]	**79**	(12)	**5**	(6)
Benefits paid	**(31)**	(31)	**(3)**	(3)
Net transfer in/(out)	**15**	-	**(2)**	-
Benefit obligation at end of year	**702**	588	**87**	81
Change in Plan Assets				
Fair value of plan assets at beginning of year	**695**	700	**-**	-
Transfer to the defined contribution component	**(2)**	(1)	**-**	-
Actual return on plan assets[1]	**78**	26	**-**	-
Employer's contributions	**4**	1	**7**	3
Benefits paid	**(31)**	(31)	**(3)**	(3)
Net transfer in	**15**	-	**-**	-
Fair value of plan assets at end of year	**759**	695	**4**	-
Funded Status				
Benefit obligation	**(702)**	(588)	**(87)**	(81)
Fair value of plan assets	**759**	695	**4**	-
Overfunded/(Underfunded) status at end of year	**57**	107	**(83)**	(81)
Contribution after measurement date	**-**	-	**-**	1
Unamortized prior service cost	**4**	5	**-**	-
Unamortized transitional (asset)/obligation	**(70)**	(94)	**16**	19
Unamortized net actuarial loss/(gain)	**228**	184	**(4)**	(9)
Net amount recognized in the Consolidated Statement of Financial Position at end of year	**219**	202	**(71)**	(70)
Presented as follows:				
Deferred Amounts and Other Assets *(Note 6)*	**222**	205	**-**	-
Other Long-Term Liabilities *(Note 10)*	**(3)**	(3)	**(71)**	(70)

1 *Includes revaluing plan assets and liabilities for December 31, 2010.*

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension Benefits		OPEB	
Year ended December 31,	**2010**	2009	**2010**	2009
Discount rate	**5.70%**	6.60%	**5.70%**	6.60%
Average rate of salary increases	**3.50%**	3.50%	**5.00%**	5.00%

Net Benefit Costs Recognized

	Pension Benefits		OPEB	
Year ended December 31,	**2010**	2009	**2010**	2009
(millions of Canadian dollars)				
Benefits earned during the year	**12**	13	**1**	1
Interest cost on projected benefit obligations	**39**	39	**5**	6
Actual return on plan assets	**(78)**	(26)	**-**	-
Actuarial loss/(gain)	**79**	(12)	**5**	(6)
Differences between costs arising in the year and costs recognized in the year:				
Return on plan assets	**29**	(22)	**-**	-
Prior service costs	**1**	1	**-**	-
Transitional (asset)/obligation	**(24)**	(25)	**3**	3
Actuarial (loss)/gain	**(64)**	25	**(5)**	6
Net defined benefit costs on an accrual basis	**(6)**	(7)	**9**	10
Defined contribution benefit costs	**2**	1	**-**	-
(Credits)/costs on an accrual basis	**(4)**	(6)	**9**	10

Costs related to the period on an accrual basis are presented above and are initially expensed. However, there is a partially offsetting adjustment due to the regulatory mechanism in place. As a result, the net expense is comprised of plan contributions and actual OPEB benefit costs paid, which is consistent with the recovery of such costs in rates. Such costs totaled $4 million for pension benefits and $7 million for OPEB for the year ended December 31, 2010 (2009 - $1 million and $3 million, respectively).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension Benefits		OPEB	
Year ended December 31,	**2010**	2009	**2010**	2009
Discount rate	**6.60%**	6.70%	**6.60%**	6.70%
Average rate of return on pension plan assets	**7.14%**	7.25%	**-**	-
Average rate of salary increases	**3.50%**	5.00%	**5.00%**	5.00%

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	9.13%	4.50%	2029
Other Medical and Dental	4.50%	4.50%	2029

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $12 million in the accumulated post-employment benefit obligations and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $10 million in the accumulated post-employment benefit obligations and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

Major Categories of Plan Assets

	Pension Benefits		
	2010		2009
As at December 31,	Allocation	Amount	Allocation
(millions of Canadian dollars)			
Equity securities	**58%**	**439**	55%
Fixed income securities	**41%**	**313**	41%
Other	**1%**	**7**	4%
Total Assets	**100%**	**759**	100%

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

The Company manages the investment risk of its defined benefit pension plans by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

Target Mix for Plan Assets	
Equity securities	52.5%
Fixed income securities	42.5%
Other	5.0%

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Year ended December 31,	**2010**	2009	**2010**	2009
(millions of Canadian dollars)				
Total contributions	**4**	1	**7**	3
Contributions expected to be paid in 2011	**5**		**4**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2011	2012	2013	2014	2015	2016-2020
(millions of Canadian dollars)						
Expected future benefit payments	38	39	41	43	45	255

18. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
Accounts receivable and other	**3**	187
Gas inventories	**(4)**	260
Accounts payable and other	**32**	20
	31	467

19. RELATED PARTY TRANSACTIONS

Year ended December 31,	**2010**	2009
(millions of Canadian dollars)		
IPL System Inc.		
Dividend income	**63**	63
Interest expense	**27**	27
Enbridge Inc.		
Purchase of treasury and other management services	**32**	28
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**30**	44
Vector Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**27**	29
Vector Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**1**	1
Alliance Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**25**	24
Alliance Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**17**	18
Enbridge Commercial Services Inc.		
Purchase of information services	**2**	2

The Company had related party balances as follows:

December 31,	**2010**	2009
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company		
Enbridge (U.S.) Inc.	**6**	7
Note receivable from affiliate company		
Enbridge (U.S.) Inc.	**-**	4
Accounts receivables/(payables)		
Enbridge Inc.	**(1)**	(2)
Gazifère Inc.	**5**	4

Financing Transactions
The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliate under common control. At December 31, 2010, the investment of $825 million (2009 - $825 million) in these shares, at cost, resulted in a weighted average dividend yield of 7.60%.

At December 31, 2010, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2010, interest paid amounted to $27 million (2009 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

Treasury and Other Management Services
Enbridge provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services.

Wholesale Service
These services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Transportation Services
The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2011 - $67 million, 2012 to 2013 - $133 million, 2014 to 2015 - $114 million and thereafter - $nil.

Information Services
The Company purchases access to a few of its customer care information systems from Enbridge Commercial Services Inc. (ECS), an affiliate under common control. ECS charges the Company amounts under a service level agreement designed to recover the cost of providing the service.

Trade Receivables and Payables
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

20. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has entered into long-term contracts and future payments under the contracts are as follows:

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Services contract [1]	22	7	13	2	-
Customer care service contracts [2]	71	57	14	-	-
CIS contracts [3]	9	6	3	-	-
Total Contractual Obligations	102	70	30	2	-

1. In 2003, the Company signed a service agreement with Accenture Inc., for a period of ten years, to provide management assistance and information technology solutions for work and asset management and field force transformation. These services relate to system improvement and expansion related construction activities performed by the Company and its construction contractors.
2. In 2007, the Company signed five-year customer care services contracts with third party service providers for meter reading, billing, billing administration, call handling, and collections.
3. In 2007, the Company signed contracts with third party service providers for CIS integration services, software maintenance and support.

CONTINGENCIES

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2011 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

Bloor Street Incident

The Company had been charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. The decision was appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Court during November and December 2009. In April 2010, the Superior Court overturned the trial judge's decision and ordered a new trial to be conducted before a different judge. The Company commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. On January 7, 2011 the Court of Appeal dismissed the Company's motion, meaning that the Superior Court's decision ordering a new trial will stand. At this time it is not certain when a new trial of the charges will commence. Management does not believe any fines that may be levied will have a material financial impact on the Company.

TAX MATTERS

The Company maintains tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATON

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

CORPORATE INFORMATION

TRUSTEE AND REGISTRARS

Debentures
9.85% and 10.80% debentures

BNY Mellon Trust Company
Corporate Trust Services
320 Bay Street, P.O. Box 1
Toronto, Ontario, M5H 4A6
and in Halifax, Montreal, Winnipeg, Regina, Calgary and Vancouver

For each of the above group of debentures, BNY Mellon Trust Company is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

Medium Term Notes
Canadian Imperial Bank of Commerce
Debt Management Service
22 Front Street, 5th Floor
Toronto, Ontario, M5J 2W5

TRUSTEE

Medium Term Notes
BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, P.O. Box 1
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

Group 3 Preferred Shares
Computershare Investor Services Inc.
100 University Avenue
Toronto, Ontario, M5J 2Y1

Corporate Governance

The size of the Board of Directors of the Company is currently set at six (6) members, two (2) of whom are considered to be independent directors.

The Board has an Audit, Finance & Risk Committee comprised of the following directors:

J. L. Braithwaite
D.A. Leslie
J. R. Bird

The Audit, Finance & Risk Committee's key responsibilities include the review of the consolidated financial statements, systems of internal financial and compliance control.

The governance of the Company is the responsibility of the Board of Directors and the Audit, Finance & Risk Committee of the Board, who are also responsible under law for the supervision of the management of the Company's businesses and affairs and have the statutory authority and obligation to act honestly and in good faith with a view to the best interests of the Company.

The Board makes independent decisions and also receives recommendations from the following committees of the Enbridge Inc. Board of Directors, who act in an advisory capacity to the Board of Directors of the Company:

- Governance Committee
- Human Resources & Compensation Committee
- Corporate Social Responsibility Committee

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the Statement of *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 29, 2010), which is incorporated herein by reference.

ENBRIDGE GAS DISTRIBUTION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2010

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 18, 2011 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) for the year ended December 31, 2010, which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). All financial measures presented in this MD&A are expressed in Canadian dollars. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

OVERVIEW

The Company is a rate-regulated natural gas distribution utility that has been in operation for more than 160 years. The Company serves approximately 2 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario, including the City of Toronto and surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, the Company serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc.

PERFORMANCE OVERVIEW

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars, except per share amounts)			
Earnings Applicable to the Common Shareholder	**191**	218	207
Earnings Excluding the Effect of Weather[1]	**203**	201	184
Cash Flow Data			
Cash provided by operating activities	**503**	971	368
Cash used by investing activities	**(365)**	(384)	(406)
Cash (used)/provided by financing activities	**(143)**	(655)	98
Dividends			
Common share dividends declared	**215**	188	159
Dividends declared per common share	**1.53**	1.34	1.12
Preferred share dividends declared	**2**	3	5
Dividends declared per preferred share	**0.52**	0.84	1.23
Total Revenues	**2,475**	2,903	3,105
Total Assets	**7,139**	6,978	6,285
Total Long-Term Liabilities	**3,871**	3,547	2,556

(1) Earnings excluding the effect of weather is a non-GAAP measure that does not have any standardized meaning prescribed by Canadian GAAP. For more information on this non-GAAP measure see page 4.

EARNINGS APPLICABLE TO THE COMMON SHAREHOLDER

Earnings applicable to the common shareholder were $191 million for the year ended December 31, 2010 compared with $218 million for the year ended December 31, 2009. The decrease of $27 million primarily resulted from warmer weather and higher depreciation and amortization expense, partially offset by customer growth, higher distribution charges and lower income taxes. Depreciation and amortization expense has increased due to an increase in the overall asset base, including the implementation of a new customer billing system in late 2009.

Earnings applicable to the common shareholder were $218 million for the year ended December 31, 2009 compared with $207 million for the year ended December 31, 2008. The increase of $11 million primarily resulted from customer growth, higher other revenue, lower interest expense and lower income taxes. This was partially offset by higher depreciation and amortization expense, higher earnings sharing with customers under the current Incentive Regulation (IR) term, higher operating and administrative costs and warmer weather.

EARNINGS EXCLUDING THE EFFECT OF WEATHER

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Earnings Applicable to the Common Shareholder	**191**	218	207
Warmer/(colder) than normal weather	**12**	(17)	(23)
Earnings Excluding the Effect of Weather	**203**	201	184

The effect of weather is measured by heating degree days and is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. Heating degree days is a key measure used by the Company to isolate the impact of weather, a factor beyond the control of management. This enables a meaningful analysis of the operational performance of the Company over different periods.

Normal weather is the weather forecast by the Company in the Greater Toronto Area (GTA), using the forecasting methodology approved by the Ontario Energy Board (OEB). Normal weather is a measure that is unique to the Company and does not have any standardized meaning. In addition, due to differing franchise areas, it is unlikely to be directly comparable to the impact of weather-normalized earnings that may be reported by other entities. Moreover, normal weather may not be comparable from year to year given that the forecasting models are updated annually to reflect the recent weather trend.

Earnings excluding the effect of weather were $203 million for the year ended December 31, 2010 compared with $201 million for the year ended December 31, 2009. Earnings increased primarily due to customer growth, higher distribution charges and lower taxes, partially offset by higher depreciation and amortization expense.

Earnings excluding the effect of weather were $201 million for the year ended December 31, 2009 compared with $184 million for the year ended December 31, 2008. Earnings increased primarily due to customer growth, higher other revenue, lower interest expense and lower income taxes. This was partially offset by higher depreciation and amortization expense, higher earnings sharing with customers under the current IR term and higher operating and administrative costs.

REVENUES

Revenues for the year ended December 31, 2010 were $2,475 million compared with $2,903 million for the year ended December 31, 2009. The decrease in revenues was primarily a result of lower natural gas prices and warmer weather compared to the prior year, partially offset by customer growth and higher distribution charges.

Revenues for the year ended December 31, 2009 were $2,903 million compared with $3,105 million for the year ended December 31, 2008. The decrease in revenues was primarily a result of lower natural gas prices and warmer weather compared to the prior year, partially offset by customer growth and higher distribution charges.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of the Company's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', ''believe'' and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to expected capital expenditures.

Although the Company believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are *not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for natural gas; prices of natural gas; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates and weather. Assumptions regarding the expected supply and demand of natural gas and the prices of natural gas are material to and underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty. The most relevant assumptions associated with forward-looking statements on expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.*

The Company's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, exchange rates, interest rates, natural gas prices and supply and demand for natural gas, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Company's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Company assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward looking statements, whether written or oral, attributable to the Company or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURE

This MD&A contains references to earnings excluding the effect of weather, which represents earnings applicable to the common shareholder adjusted for weather. Management believes that the presentation of this measure provides useful information to investors and the shareholder as it provides increased transparency and predictive value. Management uses this measure to set targets and assess performance of the Company. Earnings excluding the effect of weather is not a measure that has a standardized meaning prescribed by Canadian GAAP and is not considered a Canadian GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers.

STRATEGY

The Company's vision is to become North America's leading energy distribution and services company. To achieve its vision, the Company has outlined the following strategic objectives:

- achieve and maintain top decile safety performance;
- deliver shareholder value;
- maintain and enhance customer and stakeholder relationships;
- maintain a healthy and productive work environment; and
- enhance governance, integrity and transparency in all business processes.

The Company's strategic initiatives are designed to protect and enhance its core business with a continued focus on optimizing performance during the IR term. The Company will target new growth opportunities, which complement its core business, by pursuing newly evolving business models and technologies to support green energy initiatives. In addition, the Company will continue to grow its natural gas storage assets.

SIGNIFICANT EVENTS

Customer Care Agreement Extension
In February 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider for call centre services, collections and billing. The contract extension has been structured to provide enhanced levels of customer service. The total cost of the customer care services during the term of the extension is approximately $360 million. To become effective, the recovery of costs associated with this agreement must still be approved by the OEB. Steps are presently being taken by the Company to obtain the OEB's approval in this regard.

Cost of Capital
In December 2009, the OEB issued a report making several changes to the cost of capital for Ontario's regulated utilities. The new policy guidelines forecasted a new base level return on equity (ROE) of approximately 9.85% for the Company's 2010 rate year, which is higher than the 8.37% currently permitted. In its 2010 rate application, the Company applied to the OEB for approval to use the new ROE formula to determine the annual earnings sharing with customers for 2010 and the remainder of the IR term. While the OEB issued a decision in May 2010 that the new ROE is not to be used for such earnings sharing determinations, the Company anticipates applying the new ROE to determine rates after the conclusion of the IR term, effective for the rate year beginning 2013. In addition, the Company has appealed the OEB's May 2010 decision to the Ontario Divisional Court. The Company's appeal was heard by the Divisional Court in January 2011, but the Court has not yet released its decision.

Unregulated Storage Services
The deregulation of new natural gas storage in Ontario, coupled with the growing need for high-deliverability storage services by gas-fired power generators and other users, has created unregulated storage growth opportunities for the Company. As of December 31, 2010, the Company had expanded its storage capacity by 8% (0.2 billion cubic metres or 7.5 billion cubic feet (bcf)) and sold unregulated storage services into the storage market. A further expansion was approved by the Board of Directors in February 2011 to add an incremental 4.5 bcf of capacity.

Appointment to the Board of Directors
Effective November 1, 2010 Mr. Stephen J.J. Letwin retired from the Company's Board of Directors and Mr. David T. Robottom, Executive Vice President & Chief Legal Officer of Enbridge Inc., was appointed to the Company's Board of Directors.

RESULTS OF OPERATIONS

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Gas distribution margin	**995**	1,025	1,011
Other revenue	**108**	108	94
Operating and administrative expenses	**(393)**	(385)	(374)
Depreciation and amortization	**(270)**	(254)	(239)
Municipal and other taxes	**(44)**	(49)	(47)
Earnings sharing	**(19)**	(19)	(6)
Affiliate financing income	**63**	63	63
Interest expense	**(186)**	(190)	(201)
Income taxes	**(61)**	(78)	(89)
Earnings	**193**	221	212
Earnings Applicable to the Common Shareholder	**191**	218	207

Gas Distribution Margin
Gas distribution margin for the year ended December 31, 2010 decreased by $30 million compared with

the year ended December 31, 2009. The decrease in gas distribution margin was primarily due to warmer weather, partially offset by customer growth and higher distribution charges.

The heating degree days reported in 2010 were 80 heating degree days warmer compared with forecast heating degree days, with significant variability in the heating degree day profiles of the geographical regions in which the Company operates, unlike what was experienced in the prior year. In 2007, the OEB approved a new method for calculating normal weather in the Company's main franchise area, the GTA. However, prescribed normal weather for the Company's other service regions continues to be based on different forecasting methodologies (also approved by the OEB) than the one now used for the GTA. For the first and fourth quarters of 2010, weather in the other service regions varied from normal to a greater extent than in the GTA, thereby leading to a more significant weather normalization impact on earnings than would be typically expected. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2010 would have been higher by approximately $17 million (2009 – lower by $25 million). Weather, measured in heating degree days, was 3,466 heating degree days for the year ended December 31, 2010 compared with 3,767 heating degree days for the year ended December 31, 2009.

Gas distribution margin for the year ended December 31, 2009 increased by $14 million compared with the year ended December 31, 2008. The increase in gas distribution margin was primarily due to customer growth, favorable changes in customer mix and higher distribution charges as a result of the application of the IR formula approved by the OEB, partially offset by warmer weather compared to the prior year.

The heating degree days reported in 2009 were 253 heating degree days colder compared with forecast heating degree days. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2009 would have been lower by approximately $25 million (2008 – $35 million). Weather, measured in heating degree days, was 3,767 degree days for the year ended December 31, 2009 compared with 3,802 heating degree days for the year ended December 31, 2008.

Heating degree days were colder in 2009 and 2008 by a similar magnitude; however, there was a less significant weather normalization impact on 2009 earnings when compared to 2008 earnings due to differences in the pattern of distribution of heating degree days during the year and their relative effectiveness. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Other Revenue

Other revenue for the year ended December 31, 2010 was consistent with that of the year ended December 31, 2009. Incremental revenues during the year were derived from the management of fee-for-service energy efficiency initiatives and from unregulated storage operations due to additional contracts for storage services; however, these were offset by the inclusion of interest income in the prior year relating to recovery of a GST overpayment.

Other revenue for the year ended December 31, 2009 increased by $14 million compared with the year ended December 31, 2008. The increase was primarily due to interest income related to the recovery of the GST overpayment and revenue from the unregulated storage business, which was not fully operational in the prior year. This was partially offset by lower Shared Savings Mechanism (SSM) revenue, which results from exceeding targets on delivery of energy efficiency programs for promotion of energy efficient use of natural gas to customers.

Operating and Administrative

Operating and administrative costs for the year ended December 31, 2010 increased by $8 million compared with the year ended December 31, 2009. The increase was primarily due to higher costs relating to the management of fee-for-service energy efficiency initiatives for external parties and higher employee related costs, partially offset by lower customer support related costs relating to the implementation of a new customer billing system in late 2009.

Operating and administrative costs for the year ended December 31, 2009 increased by $11 million compared with the year ended December 31, 2008. The increase was primarily due to higher employee related costs, higher customer support related costs and higher Demand Side Management (DSM) costs incurred in connection with the promotion of energy efficient use of natural gas by customers.

Depreciation and Amortization

Depreciation and amortization charge for the year ended December 31, 2010 increased by $16 million compared with the year ended December 31, 2009. The increase was primarily due to an increase in the overall asset base mainly resulting from the implementation of a new customer billing system in late 2009.

Depreciation and amortization charge for the year ended December 31, 2009 increased by $15 million compared with the year ended December 31, 2008. The increase was primarily due to an increase in the overall asset base resulting from customer growth, spending on distribution system improvements and new information systems.

Municipal and Other Taxes

Municipal and other taxes for the year ended December 31, 2010 decreased by $5 million compared with the year ended December 31, 2009. The decrease was primarily due to the elimination of Ontario capital tax, which became effective July 1, 2010.

Municipal and other taxes for the year ended December 31, 2009 increased by $2 million compared with the year ended December 31, 2008. The increase was primarily due to tax related true-ups.

Earnings Sharing

Earnings sharing represents the estimated customer portion of regulated earnings in excess of 100 basis points above the ROE threshold currently applicable to the Company, relating to the approved IR formula for the current fiscal year and relating to the OEB’s ROE policy guideline in effect prior to December 2009. The earnings sharing mechanism results in the return of revenue of $19 million to customers for the year ended December 31, 2010 (2009 - $19 million), subject to OEB approval in 2011.

Interest Expense

Interest expense for the year ended December 31, 2010 decreased by $4 million compared with the year ended December 31, 2009. The decrease was primarily due to the Company’s redemption of its $100 million 11.15% debentures in March 2009 and lower credit facility fees resulting from more favourable market conditions.

Interest expense for the year ended December 31, 2009 decreased by $11 million compared with the year ended December 31, 2008. The decrease was primarily due to lower short-term borrowings and lower short-term interest rates. The lower requirement for borrowings was a result of lower working capital requirements due to lower natural gas prices. Partially offsetting the decrease in interest expense were higher credit facility fees.

Income Taxes

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
Earnings before income taxes	**254**	299	301
Income taxes	**61**	78	89
Effective tax rate (%)	**24.0**	26.1	29.6

The effective tax rate for the year ended December 31, 2010 was lower compared with the year ended December 31, 2009. The decrease was primarily due to a 1.0% reduction in each of the federal and Ontario income tax rates.

The effective tax rate for the year ended December 31, 2009 was lower compared with the year ended December 31, 2008. The decrease was primarily due to temporary differences relating to the CIS asset and a 0.5% reduction in the federal income tax rate.

RATE REGULATION

The utility operations of the Company and St. Lawrence are regulated by the OEB and the New York State Public Service Commission (NYSPSC), respectively (collectively the Regulators).

Incentive Regulation
In 2007, the Company filed a rate application requesting a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The OEB approved the Settlement Agreement (the Settlement) with customer representatives.

In 2008, the Company moved to an IR methodology. The objectives of the IR plan are as follows:

- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates to customers.

2011 Rate Adjustment Application
In September 2010, the Company filed an application with the OEB to adjust rates for 2011 pursuant to the approved IR formula. The total distribution revenue applied for was approved by the OEB, with the rate adjustment being effective January 1, 2011.

2010 Rate Adjustment Application
In September 2009, the Company filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. Pursuant to the subsequent filing with the OEB of a settlement agreement with ratepayer groups, the Company received approval of a fiscal 2010 final rate order from the OEB in March 2010 approving the implementation of a rate change effective April 1, 2010, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2010.

2009 Rate Adjustment Application
In September 2008, the Company filed an application with the OEB to adjust rates for 2009 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. A settlement agreement containing all applied for aspects of the formulaic component of the IR rate setting process was approved by the OEB in December 2008.

The Company received a fiscal 2009 final rate order from the OEB in February 2009 approving the implementation of a rate change effective April 1, 2009, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2009.

Impact of Rate Regulation
The Company follows Canadian GAAP, which may differ in their application to the Company's regulated operations, as compared to non-regulated businesses. These differences occur when the Regulators render their decisions on the Company's rate applications, and generally involve the timing of revenue and expense recognition to ensure that the actions of the Regulators, which create assets and liabilities, have been reflected in the consolidated financial statements.

Accounting Guideline 19 (AcG-19), *Disclosures by Entities Subject to Rate Regulation*, requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the Company's consolidated financial statements. Detailed disclosure on rate regulation is included in Note 3 to the 2010 Annual Consolidated Financial Statements.

The Company has several instances where the difference between the amount approved by the Regulators for inclusion in regulated rates and the Company's actual experience is deferred until the Regulators approve the refund to or recovery from customers.

The difference between the total natural gas distributed by the Company and the amount of natural gas billed or billable to customers for their recorded consumption, referred to as unaccounted for gas variance, is an example. To the extent the difference varies from the approved amount built into rates, the variance is deferred until the subsequent year, and upon refund or recovery, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved estimate of this variance and the related revenue, rather than the actual variance and related revenue.

There are other areas where the determination of the amounts to be recovered in current rates is different from the determination that would be reported by a non-regulated business, and the Company records those items on the same basis as they are recovered in rates. Income taxes and employee future benefits are the most significant such examples.

The recognition or omission of these items is based on an expectation of the future actions of the Regulators. For example, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. However, the regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company’s ability to pay/collect the amounts in the future through rates.

To the extent that the Regulators’ future actions are different from the Company’s current expectations, the timing and amount of recovery or refund of amounts recorded on the consolidated statement of financial position, or that would have been recorded on the consolidated statement of financial position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations, the issuance of commercial paper and credit facility draws, and the issuance of replacement long-term debt to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay dividends.

A $600 million shelf prospectus filed in May 2008 expired during the second quarter. A new $800 million shelf prospectus was filed in November 2010 and will be effective for a 25 month period. In November 2010, the Company issued $200 million of new 10 year medium-term notes (MTNs) at an interest rate of 4.04% and $200 million of new 40 year MTNs at an interest rate of 4.95%.

In 2010, the Company elected to reduce its committed credit facilities and commercial paper program limit by $100 million. The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The Company has the option, at its discretion, to extend the maturity date of the committed lines of credit for an additional year.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2010.

	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc.	**700**	**325**	**375**
St. Lawrence Gas Company, Inc.	**12**	**8**	**4**
Total Credit Facilities	**712**	**333**	**379**

1. Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the credit facility.

When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. At December 31, 2010, this ratio was 2.64 (2009 – 2.74). The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test.

Changes in natural gas prices impact accounts receivable and other, gas inventories and accounts payable and other, which may result in the working capital being negative on a temporary basis.

December 31,	**2010**	2009
(millions of Canadian dollars)		
Accounts receivable and other	**802**	801
Gas inventories	**400**	396
Bank overdraft	**(18)**	(13)
Short-term borrowings	**(332)**	(515)
Accounts payable and other	**(836)**	(781)
Working Capital	**16**	(112)

OPERATING ACTIVITIES

Cash provided by operating activities decreased to $503 million for the year ended December 31, 2010 from $971 million for the year ended December 31, 2009. The decrease primarily resulted from insignificant increases in accounts receivable and gas inventories compared to significant decreases in the prior year. These impacts are primarily the result of fluctuations in the market price of natural gas.

Cash provided by operating activities increased to $971 million for the year ended December 31, 2009 from $368 million for the year ended December 31, 2008. The increase was primarily due to a net inflow in 2009 from changes in working capital, compared to a net outflow in 2008, resulting from significant decreases in accounts receivable and gas inventories compared to increases in the prior year. These impacts were primarily the result of a significant decrease in the price of natural gas in 2009 compared to an increase in 2008.

INVESTING ACTIVITIES

In 2010, cash used for investing activities was $365 million compared with $384 million in 2009, a decrease of $19 million. The decrease was primarily due to spending in the prior year for a new customer billing system, which was implemented in late 2009, partially offset by higher comparative spending in 2010 for distribution system improvements.

Cash used for investing activities for the year ended December 31, 2009 was $384 million compared with $406 million in 2008. The decrease of $22 million was primarily due to higher comparative spending in 2008 for unregulated storage facilities and lower customer-related capital expenditures in the current year.

Capital Expenditures

Year ended December 31,	**2010**	2009	2008
(millions of Canadian dollars)			
System improvements and upgrades	**160**	144	154
System expansion	**107**	107	120
Computers and communication equipment	**32**	73	65
Land, structures and improvements	**14**	3	5
Regulated storage	**13**	3	5
Unregulated storage	**7**	12	28
Other	**32**	28	34
Total Capital Expenditures	**365**	370	411

The Company's existing distribution network consists of approximately 35,000 kilometres of underground natural gas mains and services. To support continuing customer growth, expansion of the network on an ongoing basis is required in addition to capital improvements. The Company expects to spend approximately $500 million in 2011 on capital projects. Annual capital expenditures in recent years have averaged approximately $385 million.

The 2011 capital projects include unregulated storage projects, the cast iron replacement program, power generation customer additions, the construction of a technical training facility and green energy initiatives. The Company expects to finance these expenditures through cash from operating activities and available liquidity.

FINANCING ACTIVITIES

In 2010, cash used for financing activities was $143 million compared with $655 million in 2009, a decrease of $512 million. The decrease was primarily due to $400 million of MTN issuances in 2010 and lower net repayments of short-term borrowings compared to the prior year as a result of decreased cash from operating activities, partially offset by a larger debenture maturity and an increase in common share dividends paid compared to the prior year.

In 2010, the Company issued $200 million of new 10 year MTNs at an interest rate of 4.04% and $200 million of new 40 year MTNs at an interest rate of 4.95%. In 2009, the Company did not issue any MTNs. In 2010, the Company had total debenture maturities of $150 million (2009 - $102 million).

The cash used in 2009 compared with cash generated in 2008 was primarily a result of net repayments of short-term borrowings, compared to net issuances of short-term borrowings and debentures in 2008. Increased cash from operating activities and decreased cash required for investing activities reduced financing requirements in 2009.

Short-term borrowings are used primarily to finance working capital, including gas inventories.

Preferred Shares

Floating adjustable cumulative cash dividends on the Group 3, Series D preferred shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preferred shares can be converted, at the holder's option, into Group 2, Series D preferred shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preferred shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preferred shares can also be converted into Group 3, Series D preferred shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

Outstanding Share Data[1]

	Number
Preferred Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible	4,000,000
Common shares	140,732,747

[1] Outstanding share data information is provided as at February 18, 2011.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the consolidated statements of financial position between December 31, 2009 and December 31, 2010.

Consolidated statements of financial position category	Increase/ (Decrease)	Explanation
(millions of Canadian dollars)		
Property, plant and equipment, net	168	Primarily due to capital additions relating to customer growth and system improvements, partially offset by depreciation.
Short-term borrowings	(183)	Primarily due to repayments of short-term borrowings using proceeds from a $400 million MTN issue and cash and cash equivalents generated from operations.
Accounts payable and other	55	Primarily due to higher natural gas purchase liabilities from higher purchased volumes as a result of colder weather during the last month of the year and higher amounts collected from customers under the budget billing program, partially offset by refunds of gas price variances payable to customers.
Long-term debt (including current portion)	252	Primarily due to a $400 million MTN issue, net of issuance costs, partially offset by a $150 million repayment of debentures.
Other long-term liabilities	86	Primarily due to increased future removal and site restoration reserves and an increase in the regulatory liability related to pensions.

OFF-BALANCE SHEET ARRANGEMENTS

Gas Held on Behalf of Transportation Service Customers
Transportation service customers source their natural gas supplies independently or through a broker and their estimated consumption is delivered into the Company's system evenly throughout the year. However, the consumption pattern varies from the even natural gas delivery pattern. Depending on the consumption / replenishment cycle, the Company borrows or loans natural gas from/to transportation service customers. Specific defined parameters are in place and are monitored carefully to ensure that the volume of natural gas loaned does not exceed certain threshold levels. Customer accounts beyond these defined threshold levels incur penalties. All loaned volumes are trued up annually. The Company also has strict credit policies in place to mitigate this risk. See CREDIT RISK.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2010, $102 million of natural gas was held on behalf of transportation service customers

(2009 - $164 million), a change of $62 million compared to the prior year due to lower commodity prices and lower volumes. These transactions have no impact on the Company's consolidated earnings, cash flows or financial position.

CONTINGENCIES AND COMMITMENTS

The Company is occasionally named as a party in various claims and legal proceedings which arise during the normal course of its business. The Company reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. Although there can be no assurance that any particular claim will be resolved in the Company's favour, the Company does not believe that the outcome of any claims or potential claims of which it is currently aware will have a material adverse effect on the Company, taken as a whole.

Former Manufactured Coal Gas Plant Sites
The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totalling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2011 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

Bloor Street Incident

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto in April 2003. In October 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. The decision was appealed by the Crown to the Ontario Superior Court of Justice and the appeal was heard by the Superior Court during November and December 2009. In April 2010, the Superior Court overturned the trial judge's decision and ordered a new trial to be conducted before a different judge. The Company commenced a motion for leave to appeal to the Ontario Court of Appeal and the motion was heard by the Court of Appeal in August 2010. On January 7, 2011 the Court of Appeal dismissed the Company's motion, meaning that the Superior Court's decision ordering a new trial will stand. At this time it is not certain when a new trial of the charges will commence. Management does not believe any fines that may be levied will have a material financial impact on the Company.

Tax Matters

The Company maintains tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

Other Litigation

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

CONTRACTUAL OBLIGATIONS

Payments due for contractual obligations over the next five years and thereafter are as follows:

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt [1]	2,437	150	-	400	1,887
Loans from affiliate company [1]	375	-	-	-	375
Services contract [2]	22	7	13	2	-
Customer care service contracts [3]	71	57	14	-	-
CIS contracts	9	6	3	-	-
Gas transportation contracts	752	344	247	138	23
Pension obligations [4]	9	9	-	-	-
Total Contractual Obligations	3,675	573	277	540	2,285

1. Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.
2. Primarily fees relating to services provided with respect to work and asset management initiatives. The majority of these expenditures will be capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2010, $124 million (2009 - $112 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.
3. In February 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider. The total cost of the customer care services during the term of the extension is approximately $360 million. To become effective, the recovery of costs associated with this agreement must still be approved by the OEB. Steps are presently being taken by the Company to obtain the OEB's approval in this regard.
4. Assumes only required payments will be made into the pension plans in 2011. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2010. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.

QUARTERLY FINANCIAL INFORMATION[1]

2010	**Q1**	**Q2**	**Q3**	**Q4**	**Total**
(millions of Canadian dollars)					
Revenues	**1,002**	**423**	**297**	**753**	**2,475**
Earnings applicable to the common shareholder	**86**	**28**	**8**	**69**	**191**

2009	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars)					
Revenues	1,353	469	308	773	2,903
Earnings/(loss) applicable to the common shareholder	116	32	(2)	72	218

1. Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.

Revenues include amounts billed to customers for natural gas, which varies with fluctuations in natural gas prices. Higher natural gas prices would increase revenues, but would not similarly impact earnings, given that the cost of natural gas flows through to customers.

In addition, the Company operates in a seasonal industry. Earnings for interim periods in isolation are not indicative of results for the fiscal year since volumes delivered during the peak winter months are significantly higher.

Earnings for a given quarter in two successive years may vary significantly primarily due to potentially varying weather patterns. Specifically, periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather. As a result, a meaningful comparison can only be achieved after adjusting earnings for the impact of weather.

Further, as a result of continued changes in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, a portion of revenues and earnings will shift from the colder winter quarters progressively to the warmer summer quarters, with no material impact on full year revenue and earnings. This change will also impact the comparability of a given quarter from year to year.

FOURTH QUARTER 2010 HIGHLIGHTS

Earnings applicable to the common shareholder were $69 million for the three months ended December 31, 2010 compared with $72 million for the same period in 2009. The decrease of $3 million was primarily due to tax differences relating to intangible assets, partially offset by lower interest expense from lower credit facility fees.

RELATED PARTY TRANSACTIONS

The Company had transactions with related parties during the year. Amounts are invoiced on a monthly basis and are usually due and paid on a quarterly basis.

IPL System Inc. The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliated company under common control. At December 31, 2010, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2010, dividends received amounted to $63 million (2009 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2010 (2009 - $5 million).

IPL System Inc. advanced the Company $375 million ($200 million at 6.85% and $175 million at 7.50%) repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2010, interest paid amounted to $27 million (2009 - $27 million) with an outstanding payable balance of $2 million at December 31, 2010 (2000 - $2 million).

Enbridge (U.S.) Inc., an affiliated company under common control, advanced the Company $6 million (2009 - $7 million) at the LIBOR rate plus 0.55%, payable on demand.

Enbridge Inc., the ultimate parent company, provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services. Charges incurred for the year ended December 31, 2010 were $32 million (2009 - $28 million) with an outstanding payable balance of $1 million at December 31, 2010 (2009 - $2 million).

Gazifère Inc., an affiliated company under common control, purchases wholesale services from the Company. These services are pursuant to a contract negotiated between the two companies and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie. Total revenues for the year ended December 31, 2010 were $30 million (2009 - $44 million) with an outstanding receivable of $5 million at December 31, 2010 (2009 - $4 million).

Vector Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2010 were $27 million (2009 - $29 million) with an outstanding payable of $nil at December 31, 2010 (2009 - $nil).

Vector Pipeline Limited Partnership (Canadian), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2010 were $1 million (2009 - $1 million) with an outstanding payable of $nil at December 31, 2010 (2009 - $nil).

Alliance Pipeline Limited Partnership (Canadian), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2010 were $25 million (2009 - $24 million) with an outstanding payable of $nil at December 31, 2010 (2009 - $nil).

Alliance Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2010 were $17 million (2009 - $18 million) with an outstanding payable of $nil at December 31, 2010 (2009 - $nil).

Enbridge Commercial Services Inc., an affiliated company under common control, provides information services to the Company. Total charges for the year ended December 31, 2010 were $2 million (2009 - $2 million) with an outstanding payable of $nil million at December 31, 2010 (2009 - $nil).

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company has formal risk management policies, procedures and systems designed to mitigate the risks described below. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

REGULATORY RISK

The formula currently approved by the OEB for determination of the ROE, which is embedded and escalated within rates over the IR period, is based on the OEB's risk assessment of the Company for the 2007 fiscal year.

In December 2009, the OEB issued a report making several changes to the cost of capital for Ontario's regulated utilities. The new policy guidelines forecasted a new base level ROE of approximately 9.85% for the Company's 2010 rate year, which is higher than the 8.37% currently permitted. In its 2010 rate application, the Company applied to the OEB for approval to use the new ROE formula to determine the annual earnings sharing with customers for 2010 and the remainder of the IR term. While the OEB issued a decision in May 2010 that the new ROE is not to be used for such earnings sharing determinations, the Company anticipates applying the new ROE to determine rates after the conclusion of the IR term, effective for the rate year beginning 2013. In addition, the Company has appealed the OEB's May 2010 decision to the Ontario Divisional Court. The Company's appeal was heard by the Divisional Court in January 2011, but the Court has not yet released its decision.

The Settlement allows certain Y and Z factors (which represent specific categories of expense from a Cost of Service (COS) view and uncontrollable external factors, respectively) in the IR formula, which will permit the Company to recover, with OEB approval, certain costs that are beyond management control, but are necessary for the maintenance of its services. The Settlement also includes a mechanism to reassess the IR plan and return to COS if there are significant and unanticipated developments that threaten the sustainability of the IR plan. The above noted terms set out in the Settlement mitigate the Company's risk to factors beyond management's control.

The Company does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased, including risk management costs for St. Lawrence, and the price approved by the Regulators. This difference is deferred as a receivable from or payable to customers until the Regulators approve its refund or collection. The Company monitors the balance and its potential impact on customers and will request interim rate relief that will allow the Company to recover or refund the natural gas cost differential.

The Company, excluding St. Lawrence, has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB.

VOLUME RISKS

Since customers are billed on both a fixed charge and on a volumetric basis, the Company's ability to collect its total IR formula revenue depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts are reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Over the life of the current IR agreement, the portion of fixed charges will increase annually thereby reducing this risk.

Weather is a significant driver of delivery volumes, given that a significant portion of the Company's customer base uses natural gas for space heating. Weather, measured in terms of heating degree days, normally directly impacts earnings of the Company as noted below. Heating degree days is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

Factor	Incremental change	Approximate incremental impact
Weather	18 heating degree days	1 billion cubic feet
Volume	1 billion cubic feet	$1.3 million (after-tax)

An unusual pattern of distribution of heating degree days during the year and their relative effectiveness may impact the above sensitivity. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continues to place downward pressure on consumption. In addition, conservation efforts by customers further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 80% (2009 - 81%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where the Company attains its total forecast distribution volume, the Company may not earn the expected ROE due to other forecast variables such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector.

This distribution volume risk for general service customers is mitigated by the average use true-up variance account that was established under the IR Settlement Agreement. This variance account enables recovery from or repayment to customers amounts representing variances in the actual and forecast average use by general service customers. The Company remains at risk of distribution volume for large volume contract commercial and industrial customers.

MARKET PRICE RISK

The Company's earnings, cash flows and other comprehensive income are subject to movements in interest rates, foreign exchange rates and natural gas commodity prices (collectively, market price risk).

The following section summarizes the primary types of market price risks to which the Company is exposed and outlines the financial derivative hedging programs implemented.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt obligations. Floating to fixed interest rate swaps and options may be used to hedge against the effect of future period interest rate movements. The Company has implemented a hedging program to mitigate the volatility to variable rate interest expense through 2012 at an average rate of 1.8%.

Foreign Exchange Risk
Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is $nil.

Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Historically, the Company had managed the exposure to natural gas price risk by entering into fixed price natural gas contracts; however, in compliance with the directive of the OEB, the Company no longer manages the natural gas price risk exposure on behalf of customers other than for St. Lawrence customers. Fluctuations in natural gas prices are borne by the customers.

CREDIT RISK
Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables.

The Company minimizes credit risk to derivative counterparties by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty.

FINANCING RISK
The Company's financing risk relates to the price volatility and availability of debt to finance capital expenditures and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian debt market conditions can change dramatically, affecting capital availability.

To address this risk, the Company maintains sufficient liquidity through committed credit facilities with its diversified banking groups designed to enable the Company to fund all anticipated requirements for one year without accessing the capital markets. In addition, the Company strives to ensure that it can readily access the Canadian public capital markets by maintaining a current shelf prospectus with the securities regulators.

LIQUIDITY RISK
Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments, as they become due. To manage this risk, the Company forecasts the cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets.

MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES
For the years ending December 31, 2011 through 2015, and thereafter, the Company has estimated that the following undiscounted cash flows will arise from its derivative instruments based on valuation at the

balance sheet date.

	2011	2012	2013	2014	2015	Thereafter
(millions of Canadian dollars)						
Cash inflows	-	-	-	-	-	-
Cash outflows	(1)	-	-	-	-	-
Net Cash Flows	(1)	-	-	-	-	-

FINANCIAL INSTRUMENTS

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Accounts receivable and other	**-**	**-**	**722**	**-**	**-**	**80**	**802**	**722**
Investment in affiliate company	**-**	**825**	**-**	**-**	**-**	**-**	**825**	**N/A**
Deferred amounts and other assets	**-**	**-**	**-**	**-**	**-**	**487**	**487**	**-**
Liabilities								
Bank overdraft	**18**	**-**	**-**	**-**	**-**	**-**	**18**	**18**
Short-term borrowings	**-**	**-**	**-**	**332**	**-**	**-**	**332**	**332**
Accounts payable and other	**-**	**-**	**-**	**597**	**1**	**238**	**836**	**598**
Long-term debt	**-**	**-**	**-**	**2,417**	**-**	**-**	**2,417**	**2,775**
Loans from affiliate company[2]	**-**	**-**	**-**	**375**	**-**	**-**	**375**	**N/A**

December 31, 2009	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Accounts receivable and other	-	-	691	-	2	108	801	693
Investment in affiliate company	-	825	-	-	-	-	825	N/A
Deferred amounts and other assets	-	-	-	-	4	483	487	4
Liabilities								
Bank overdraft	13	-	-	-	-	-	13	13
Short-term borrowings	-	-	-	515	-	-	515	515
Accounts payable and other	-	-	-	474	3	304	781	477
Long-term debt	-	-	-	2,165	-	-	2,165	2,445
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

1 Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market.

2 Loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined.

Fair Value of Financial Instruments

The fair value of financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such prices are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of cash and cash equivalents, bank overdraft and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

DERIVATIVE INSTRUMENTS

The following table summarizes the maturity and total notional principal or quantity outstanding related to the Company's derivative instruments.

December 31, 2010	2011	2012	2013	2014	2015	Thereafter
Natural gas *(10^6m^3)*	17	6	-	-	-	-
Interest rate contracts *(millions of Canadian dollars)*	279	111	-	-	-	-
Net Cash Flows	296	117	-	-	-	-

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 13 and 14 of the 2010 Annual Consolidated Financial Statements.

GENERAL BUSINESS RISKS

Distribution Operating Risk

The Company's distribution network is exposed to operational risks such as accidental damage to mains and service lines, corrosion leaks in mains and service lines, breaks in cast iron pipes, malfunction of compression and decompression equipment and other issues that can lead to outages. Leaks in the distribution system are an inherent risk of operations. A comprehensive surveillance, maintenance and repair program as well as the phased replacement of cast iron pipes significantly reduces the exposure.

Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the distribution network. The occurrence or continuance of any of these events could increase the cost of operating the Company's distribution network or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage pipeline integrity, which includes the development and use of in-line inspection tools for pipelines. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While the Company considers the level of insurance to be adequate, it may not be sufficient to cover all potential losses.

Environmental, Health and Safety Risk

The Company's operations are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and distribution network must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities and the distribution network are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas (GHG) emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. The Company could be targeted by environmental groups attempting to draw attention to GHG emissions.

The Company is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment, benefits everyone and delivers increased value to the shareholder, customers and employees. The Company has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

Climate Change Legislation

The Canadian Federal Government has indicated that Canada will target a 17% reduction of GHG emissions by 2020, based on 2006 emission levels. It has also signaled that 90% of Canada's electricity will be provided by non-emitting sources, such as hydro, nuclear, clean-coal, solar and wind, by 2020. Details of Canada's GHG management plan will not be released until there is clarity in the United States about its intention to regulate GHG emissions. Canadian regulations will likely be compatible with those of the United States in order for Canadian businesses to remain competitive and avoid the potential for punitive trade sanctions. It is uncertain how climate legislation could affect the industry. The Company continues to monitor developments.

Reputation Risk

The Company's reputation is very important. Reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders and other entities. These potential impacts may include loss of business, legal action or increased regulatory oversight.

Reputation risk often arises as a consequence of some other risk event, such as operating, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations;
- having strong corporate governance practices, including a Statement on Business Conduct, with which all employees are required to certify their compliance on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy, implemented through the Company's Corporate Social Responsibility Policy.

Workforce

The potential lack of qualified and properly trained technical, professional and operational staff and leaders would increase the risk that the Company will not be able to implement its corporate strategy. This risk may be compounded by the increasing rates of retirement due to workforce demographics, turnover due to competition in certain markets and growing demand for staff to support business growth. The Company continues to monitor company-wide workforce planning. The Company offers competitive compensation programs, training, leadership development and succession planning. Further, the supply of human resources is balanced between hiring full-time employees and expanding the contractor workforce.

Approximately 35% of the Company's workforce is represented by the Communications, Energy and Paperworkers Union, Local 975 (CEPU) or the International Brotherhood of Electrical Workers (IBEW), Local 97. The current collective agreement with CEPU expired in December 2010 and a new collective agreement is being negotiated. The terms of the prior agreement remain in force until the new agreement is ratified by the union members. Also in December 2010, a four-year collective agreement was signed with the IBEW, expiring in February 2015.

CRITICAL ACCOUNTING ESTIMATES

REVENUE RECOGNITION

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced.

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2010 of $4,458 million (2009 - $4,290 million), or 62% of total assets (2009 – 62%), is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

These depreciation rates are reviewed through periodic depreciation studies conducted by an external consulting firm that makes an objective assessment of the useful lives of the Company's property, plant and equipment. The depreciation rates used by the Company are subject to approval by the OEB for rate setting purposes, which may not always reflect the recommendations of the latest depreciation study. The last such study was completed in 2010. The external consulting firm also provides a framework for the Company's calculation of the estimate of the net cumulative amount collected from customers for future site removal and restoration of property, plant and equipment.

REGULATORY ASSETS AND LIABILITIES

The Regulators exercise statutory authority over matters such as construction, rates and rate-making, and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the Regulators. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2010, the Company's regulatory assets totaled $296 million (2009 - $299 million) and regulatory liabilities totaled $1,171 million (2009 - $1,165 million). To the extent that the Regulators' actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees as well as OPEB to eligible retirees.

Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. However, there is significant measurement uncertainty incorporated into the actuarial valuation process. For example, there is no assurance that the pension plan will be able to earn the assumed rate of return.

Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. However, no earnings impact would result due to the continuity of the existing regulatory mechanism in place under which plan contributions and actual OPEB benefit costs are expensed as paid, consistent with the recovery of such costs in rates.

The Company's plan remains in a surplus position thus precluding any contribution requirements by the Company. The difference between the actual and expected return on plan assets was an excess of $29 million for the year ended December 31, 2010 (2009 – a shortfall of $22 million) as disclosed in Note 17 to the 2010 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension plans, funding in 2011 will be $9 million.

The following sensitivity analysis identifies the impact on the December 31, 2010 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
(millions of Canadian dollars)	Obligation	Expense	Obligation	Expense
Decrease in discount rate	46	5	6	-
Decrease in expected return on assets	n/a	3	n/a	-
Decrease in rate of salary increase	(7)	(2)	-	-

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company, are detailed in the Commitments and Contingencies section of this report and are disclosed in Note 20 of the 2010 Annual Consolidated Financial Statements.

REGULATORY GOVERNANCE

Undertakings

The Company, and its parent Enbridge Inc., have entered into Undertakings with the Lieutenant Governor in Council for Ontario that commit Enbridge Inc. and the Company to certain obligations relating to the maintenance of common equity, as well as restrictions on diversification to the effect that the Company must not carry on, except through an affiliate or affiliates, any business activity other than the distribution, storage or transmission of natural gas without the OEB's prior approval. In compliance with these undertakings, the Company has obtained OEB approval to carry on the Natural Gas Vehicle Program, Agent Billing and Collection Program and Gas Sales and Oil Production activity.

In August 2006, the Government of Ontario approved changes to the Undertakings that allow the Company to provide services related to the promotion of electricity conservation, natural gas conservation and the efficient use of electricity, electricity load management, and the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. In addition, the Company is allowed to engage in activities and provide services related to the local distribution of steam, hot and cold water in an initiative with Markham District Energy Inc., and pursuit of a pilot project for the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

In September 2009, Ontario's Minister of Energy and Infrastructure issued a Directive that permits the Company to own and operate stationary fuel cells, wind, water, biomass, biogas, solar and geothermal energy generation facilities up to 10 megawatts in capacity. The Company will also be permitted to own and operate district and distributed energy systems, including facilities that produce power and thermal energy from a single source. Finally, the Minister's Directive permits the Company to own and operate assets that would assist the Government of Ontario in achieving its goals in energy conservation, including assets related to solar-thermal water and ground source heat pumps.

In the absence of the Minister's Directive, the Company's Undertakings to the Lieutenant Governor in Council would not have permitted the Company to engage in the foregoing activities directly. The Company plans to increase its role in this area and is looking to expand its efforts to explore and pursue alternative and/or renewable energy technologies subject to OEB approval, where appropriate.

While the Directive permits the Company to engage in such activities, in December 2009 the OEB determined that it would not allow such activities to be included in rate-making for the purposes of setting 2010 rates. The Company continues to engage the government, regulators and other stakeholders to determine what alternatives are available to the Company to undertake these investments in the future.

Affiliate Relationships Code
The Company is subject to the provisions of the OEB's Affiliate Relationships Code for Gas Utilities (the Code). The Code sets out the standards and conditions that govern the interaction between natural gas distributors, transmitters and storage companies in Ontario and their respective affiliated companies and is intended to:

- minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities;
- protect the confidentiality of consumer information collected in the course of providing utility services; and
- ensure there is no preferential access to regulated utility services.

The Code specifically sets out standards of conduct including the degree of separation, sharing of services and resources, terms under which service agreements must be prepared and transfer pricing guidelines.

CHANGE IN ACCOUNTING POLICIES

FUTURE ACCOUNTING POLICIES

International Financial Reporting Standards (IFRS)

First-time adoption of Part I - International Financial Reporting Standards (Part I) of the Canadian Institute of Chartered Accountants (CICA) Handbook is mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I is mandatory for qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and it will continue to present its financial statements in accordance with Part V - Pre-changeover Accounting Standards of the CICA Handbook during the 2011 deferral period.

While the Company's IFRS conversion project was on track to meet the original conversion deadline, the Company has elected to use the one year deferral offered by the Canadian Accounting Standards Board. This decision was made given the continuing uncertainty with respect to the basis of application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business model and performance measurement. The International Accounting Standards Board (IASB) originally issued an exposure draft on rate regulated activities in 2009, but has since failed to finalize the accounting standard or provide definitive guidance on the direction of the project.

During the 2011 deferral period, the Company will present its financial statements in accordance with Part V of the CICA Handbook, will continue to closely monitor developments of the IASB, and will determine whether IFRS or U.S. GAAP would provide the most useful and reliable presentation of its financial results for 2012 and future periods.

Business Combinations

CICA Handbook Section 1582, Business Combinations, replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination to be expensed in the period in which they are incurred. The adoption of this standard will impact the Company's accounting treatment of any future business combinations occurring on or after January 1, 2011.

Consolidated Financial Statements and Non-Controlling Interests

The CICA issued Handbook Sections 1601, Consolidated Financial Statements and 1602, Non-controlling Interests, which together replace the former consolidated financial statements standard. Under the revised standards, non-controlling interests will be classified as a component of equity, and earnings and comprehensive income will be attributed to both the parent and non-controlling interest. The adoption of these standards is not expected to have a material impact to the Company's consolidated earnings or cash flows. The revised standards are effective January 1, 2011.

ENBRIDGE GAS DISTRIBUTION INC.
HIGHLIGHTS

Year ended December 31,	**2010**	2009
Financial *(millions of Canadian dollars)*		
Gas commodity and distribution revenue	**1,977**	2,346
Transportation of gas for customers	**390**	449
Other revenue	**108**	108
Total revenue	**2,475**	2,903
Gas commodity and distribution costs	**(1,372)**	(1,770)
Net revenue	**1,103**	1,133
Earnings	**193**	221
Earnings applicable to the common shareholder	**191**	218
Return on equity[1] (%)	**10.3**	11.8
Operating		
Volumetric Statistics *(millions of cubic metres)*		
Gas commodity sales	**5,550**	5,513
Transportation of gas for customers	**5,584**	6,035
Unbundled volumes[2]	**460**	341
Total volume	**11,594**	11,889
Number of active customers[3] *(thousands)*	**1,981**	1,937
Heating degree days[4]		
Actual	**3,466**	3,767
Forecast based on normal weather	**3,546**	3,514

1. Return on equity data relates to the consolidated entity.
2. Unbundled customers deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.
3. Active customers is the number of natural gas consuming customers at the end of the year.
4. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. The figures given are those accumulated in the GTA.