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

Lorraine Chiasson
Regulatory Coordinator
phone: (416) 495-5499
fax: (416) 495-6072
Email: lorraine.chiasson@enbridge.com

June 24, 2013

VIA EMAIL, RESS, 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")
2012 Earnings Sharing Mechanism and Other Deferral
And Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2013-0046**

Further to Enbridge Gas Distribution's filing of the ESM application on May 24, 2013 enclosed please find the following corrected exhibits reflecting the correction to the docket number.

Exhibit B, Tab 1, Schedule 2; and
Exhibit C, Tab 1, Schedule 6.

Also enclosed please find Appendix D for Exhibit C, Tab 1, Schedule 6 which was inadvertently missed in the original filing.

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 at www.enbridgegas.com/ratecase.

Yours truly,

(Original Signed)

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties EB-2011-0354 (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 – 2012 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 2012 Historical Year	K. Culbert R. Small
		3	Utility Earnings – Comparison of 2012 Historical Year to 2007 Board Approved	K. Culbert R. Small
		4	Utility Earnings – Reconciliation of 2012 Utility Income to Audited EGDI Consolidated Income	K. Culbert R. Small
	2	1	Ontario Utility Rate Base – Comparison of 2012 Historical Year to 2011 Historical Year	K. Culbert R. Small
		2	Ontario Utility Rate Base – Comparison of 2011 Historical Year to 2010 Historical Year	K. Culbert R. Small
		3	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2012 Historical Year	K. Culbert R. Small

EXHIBIT LIST

B – 2012 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	2	4	Comparison of Utility Capital Expenditures Actual 2012 and Actual 2011	L. Au S. Qian
		5	Comparison of Utility Capital Expenditures Actual 2011 and Actual 2010	L. Au S. Qian
	3	1	Utility Operating Revenue 2012 Historical Year	K. Culbert R. Small
		2	Comparison of Gas Sales and Transportation Volume by Rate Class 2012 Actual to 2012 Board Approved Budget	C. Ho S. Riccio
		3	Comparison of Gas Sales and Transportation Revenue by Rate Class 2012 Historical Year to 2012 Board Approved Budget	C. Ho S. Riccio
		4	Customers Meters, Volumes and Revenues by Rate Class 2012 Actual	C. Ho S. Riccio
		5	Details of Other Revenue 2012 Historical Year to 2011 Historical Year	R. Lei S. Qian
		6	Details of Other Revenue 2011 Historical Year to 2010 Historical Year	R. Lei S. Qian
	4	1	Operating Cost 2012 Historical Year	K. Culbert R. Small
		2	Operating and Maintenance Expense by Department Ending December 2012	R. Lei S. Qian
	5	1	Required Rate of Return 2012 Historical Year	K. Culbert R. Small

EXHIBIT LIST

B – 2012 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	5	2	Utility Income 2012 Historical Year	K. Culbert R. Small
		3	Cost of Capital 2012 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 January 1, 2014	K. Culbert R. Small
		2	Gas Distribution Access Rule Cost Deferral Account explanation	K. Culbert R. Small
		3	Average Use True Up Variance Account explanation	C. Ho S. Riccio
		4	2012 Tax Rate and Rule Change Variance Account (TRRCVA)	K. Culbert R. Small
		5	2012 Ontario Hearing Costs Variance Account (OHCVA)	K. Culbert R. Small
		6	Transactional Services Revenue	J. LeBlanc D. Small M. Giridhar
	2	1	Clearance of Deferral and Variance Account Balances	J. Collier A. Kacicnik M. Kirk
		2	Derivation of Proposed Unit Rates	J. Collier A. Kacicnik

EXHIBIT LIST

M. Kirk

D – REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	Enbridge Gas Distribution Inc. Consolidated Financial Statements December 31, 2012	B. Yuzwa
		2	Enbridge Gas Distribution Inc. Management's Discussion and Analysis – December 31, 2012	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.

A P P L I C A T I O N

1. The Applicant, Enbridge Gas Distribution Inc. ("Enbridge", or the "Company") 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 December 31, 2012, Enbridge had concluded the final 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 Interim and Final Orders in EB-2011-0277 approved the establishment of Enbridge's

deferral and variance accounts for 2012, and these accounts are set out in Appendix A to this Application.

4. Among the deferral and variance accounts listed in Appendix B to the Settlement Agreement is the Earnings Sharing Mechanism Deferral Account (“ESMDA”). The Settlement Agreement states that Enbridge will file 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.

5. Enbridge therefore applies to the Board for such final, interim or other Orders as may be necessary or appropriate for the clearance or disposition of the 2012 ESMDA and the other deferral and variance accounts listed in Appendix A to this Application.

6. Enbridge’s Customer Information System (CIS) is scheduled for maintenance in the fall of 2013 and, as a result, the earliest feasible opportunity for clearance of the 2012 ESMDA and other deferral and variance accounts is at the time of the January 1, 2014 QRAM filing. Accordingly, Enbridge proposes to clear the balances in its deferral and variance accounts as approved in this proceeding in conjunction with the January 1, 2014 QRAM 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:	416-495-5499
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 May 24, 2013 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: (Original Signed)

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

			Col. 1	Col. 2	Col. 3	Col. 4	
			Actual at March 31, 2013		Forecast for clearance at January 1, 2014		
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	2011 DSMVA	535.8	(46.8)	535.8	(40.5)	[1]
2.	Lost Revenue Adjustment Mechanism	2011 LRAM	-	-	(55.3)	(0.5)	[1]
3.	Shared Savings Mechanism V/A	2011 SSMVA	-	-	6,769.5	41.5	[1]
4.	Deferred Rebate Account	2012 DRA	(940.8)	(5.8)	(940.8)	(16.6)	
5.	Gas Distribution Access Rule Costs D/A	2011 GDARCDA	89.9	1.7	-	-	[2]
6.	Gas Distribution Access Rule Costs D/A	2012 GDARCDA	1,616.4	12.6	1,097.8	-	[2]
7.	Ontario Hearing Costs V/A	2012 OHCVA	(1,259.7)	(5.7)	(1,259.7)	(19.2)	[3]
8.	Unbundled Rate Implementation Cost D/A	2012 URICDA	155.0	1.5	155.0	3.3	
9.	Average Use True-Up V/A	2012 AUTUVA	4,361.3	16.0	4,361.3	63.7	[4]
10.	Tax Rate and Rule Change V/A	2012 TRRCVA	300.0	1.4	300.0	5.0	[5]
11.	Earnings Sharing Mechanism D/A	2012 ESMDA	(10,350.0)	(38.0)	(10,350.0)	(152.3)	[6]
12.	Electric Program Earnings Sharing D/A	2012 EPESDA	(281.7)	(1.0)	(281.7)	(3.7)	
13.	Ex-Franchise Third Party Billing Services D/A	2012 EFTPBSDA	(143.0)	(0.5)	(143.0)	(2.3)	
14.	Transition Impact of Accounting Change D/A	2013 TIACDA	88,716.0	-	4,435.8	-	[7]
15.	Total non commodity related accounts		82,799.2	(64.6)	4,624.7	(121.6)	
	Commodity Related Accounts						
16.	Transactional Services D/A	2012 TSDA	(26,077.3)	(208.0)	(26,077.3)	(495.1)	
17.	Unaccounted for Gas V/A	2012 UAFVA	2,067.9	7.6	2,067.9	30.1	
18.	Storage and Transportation D/A	2012 S&TDA	(699.8)	(7.4)	(699.8)	(15.5)	
19.	Total commodity related accounts		(24,709.2)	(207.8)	(24,709.2)	(480.5)	
20.	Total Deferral and Variance Accounts		58,090.0	(272.4)	(20,084.5)	(602.1)	

Notes:
1. The final 2011 DSMVA, SSMVA, and LRAM balances to be cleared will be those approved in the EB-2013-0075 proceeding, anticipated to be filed in Q2 2013.
2. The $1.1M forecast clearance amount, associated with the 2011 and 2012 GDARCDA balances, is the result of a revenue requirement calculation found in evidence at Ex.C-1-2.
3. The OHCVA calculation is found in evidence at Ex.C-1-5.
4. The AUTUVA explanation is found in evidence at Ex.C-1-3.
5. The TRRCVA explanation is found in evidence at Ex.C-1-4.
6. The ESMDA explanation is found in evidence at Ex.B-1-1 and B-1-2.
7. The TIACDA clearance is in accordance with the EB-2011-0354 Final Rate Order.

APPROVALS REQUESTED

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

   a) The Company has filed the balances at March 31, 2013, of Board approved deferral and variance accounts and is requesting approval for their clearance commencing January 1, 2014, (Exhibit C, Tab 1, Schedule 1). While the EB-2007-0615 Settlement Agreement anticipated that clearance of such accounts would occur in conjunction with each following fiscal year's July 1st QRAM, within each of the process timelines experienced in each of EGD's 2008, 2009, 2010, and 2011 proceedings, the earliest that clearance occurred was on October 1st of the following fiscal year. As indicated in evidence in Exhibit C-1-1, due to a required billing system SAP upgrade in September/October 2013, clearance of the balances is proposed as a one time Billing adjustment to customers' bills coincident with the Company's January 1, 2014 Quarterly Rate Adjustment Mechanism filing.

   b) Included within the deferral and variance account balances requested for clearance is the 2012 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 2012 financial statements are filed within Exhibit B, Tabs 1 through 6 and Exhibit D, Tab 1.

Witness: K. Culbert

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 January 1, 2014 QRAM proceeding, a Board Decision or approval is required by approximately November 15, 2013.

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 within 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 has filed the ESM calculations within 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.

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-2012-0055 EB-2011-0354 EB-2011-0008 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-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0226
EB-2011-0008
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
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-2012-0055
EB-2011-0354
EB-2011-0277
EB-2010-0146
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-3758-2011
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
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-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0226
EB-2011-0008
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
MALINI GIRIDHAR

Experience:	Enbridge Gas Distribution Inc.
	Vice President, Gas Supply 2013
	Senior Director, Gas Supply and GTA Project 2012
	Director, GTA Project 2011
	Director, Energy Supply and Policy 2007
	Manager, Rate Research and Design 2003
	Manager, Rate Design 1999
	Manager, Rate Research 1997
	Financial Analyst, Financial Studies 1994
	Borealis Energy Research Consultants
	Consultant 1994
	Gas and Fuel Corporation of Victoria, Australia
	Senior Analyst, Tariffs 1992
	Economic Analyst 1989
Education:	Chartered Financial Analyst, 2005
	Master of Philosophy (Econometrics) University of Madras, India, 1988
	Master of Arts (Economics) Gokhale Institute of Politics and Economics, India, 1987

Appearances: (Ontario Energy Board)
EB-2010-0333
EB-2010-0231
EB-2008-0106
EB-2008-0219
EB 2006-0034
EB-2005-0551
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
RP-1999-0001
EBRO 497

(National Energy Board)
RH-003-2011

(Régie de l'énergie)
R-3537-2004
R-3464-2001
R-3430-99
R-3406-98

CURRICULUM VITAE OF
CATHERINE HO, CPA, CA

Experience: Enbridge Gas Distribution Inc.

Manager, Accounting
2012

Manager, Gas Accounting
2012

Manager, Finance Projects
2008

Senior Audit Advisor
2005

Ernst & Young LLP

Senior Staff Accountant
2004

Horwath Orenstein LLP

Staff Accountant
2002

Goldfarb, Shulman, Patel & Co. LLP

Staff Accountant
2000

Education: Chartered Accountant, 2005

Certified Public Accountant – Delaware, 2004

University of Waterloo – Waterloo ON
Master of Accounting (MAcc), 2003
Bachelor of Arts Honours Chartered Accountancy Studies – Co-operative program (Dean's Honours List), 2002

Memberships: Institute of Chartered Accountants of Ontario (ICAO)

Appearances: (Ontario Energy Board)
None

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-2012-0055 EB-2011-0354 EB-2011-0277 EB-2011-0008 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
MATTHEW KIRK

Experience:	Enbridge Gas Distribution Inc.
	Cost Allocation Manager, Regulatory Affairs 2012
	Senior Rate Design Analyst, Regulatory Affairs 2010
	Rate Design Analyst, Regulatory Affairs 2009
	Market Analyst, Economic and Market Analysis 2006
Education:	Master of Arts (Economics) Wilfrid Laurier University, 2006
	Bachelor of Arts (Honours Economics) McMaster University, 2005
Memberships:	Canadian Association of Business Economists (CABE)
Appearances:	(Ontario Energy Board) EB-2012-0055 EB-2011-0354
	(Régie de L'Energie) R-3793-2012

CURRICULUM VITAE OF
JAMIE LeBLANC

Experience:	Enbridge Gas Distribution Inc.
	Director, Energy Supply and Policy 2013
	General Manager - Gazifère Inc. 2010
	Enbridge Gas New Brunswick Inc.
	Manager, Finance and Control 2005
	Supervisor, Financial Reporting 2004
Education:	Chartered Accountancy Designation Atlantic School of Chartered Accountants, 1998
	Bachelor Business Administration University of New Brunswick, Fredericton, 1996
Memberships:	The New Brunswick Institute of Chartered Accountants
Appearances:	(Régie de l'énergie/Régie du gaz naturel) R-3793-2012 R-3758-2011
	(New Brunswick Energy and Utilities Board) Cost of Capital for Enbridge Gas New Brunswick (EGNB) – 2010 EGNB Financial Results 2009 – 2010 EGNB Cost of Service Study – 2010 EGNB LFO Rate Changes – 2010 EGNB Various Rates and HFO Rates - 2010 EGNB Development Period – 2009 EGNB Financial Results 2008 – 2009 EGNB Financial Results – 2007 - 2009

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-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172

CURRICULUM VITAE OF
SANDEE QIAN

Experience:	Enbridge Gas Distribution Inc.
	Ops Budget & Analysis Manager, Finance 2012
	Manager Margin Budget & Analysis, Finance 2010
	Manager Financial Analysis, Corporate Budget & Analysis 2008
	Program Manager Capital Appropriation & Scorecard, Finance 2006
	Senior Financial Analyst, Financial Assessment 2006
	Financial Analyst, Financial Assessment 2004
	Motorola (China) Electronics Ltd.
	Senior Analyst 1995
Education:	Certified Management Accountant (CMA), 2007
	Master of Business Administration York University, 2003
	Bachelor of Engineering Northwestern Polytechnic University, China
Memberships:	The Society of Management Accountants Ontario
Appearances:	(Ontario Energy Board) EB-2011-0354

CURRICULUM VITAE OF
STEVEN RICCIO

Experience:	Enbridge Gas Distribution Inc.
	Senior Analyst, Gas Accounting & Analytics 2010 - Present
	Analyst, Revenue Accounting & Business Analytics 2009 - 2010
	SAP Business Analyst, Margin Budgets & Accounting 2008 - 2009
Education:	Bachelor of Commerce, Ryerson University, 2008
Memberships:	N/A
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
DONALD R. SMALL

Experience:	Enbridge Gas Distribution Inc.
	Manager, Gas Costs and Budget 2010
	Manager, Gas Cost Knowledge Centre 2003
	Manager, Gas Costs and Budget 1989
	Co-ordinator, Gas Costs 1984
	Financial Statement Accountant 1980
	Chief Clerk, Financial Statements 1979
	Advanced Accounting Trainee 1978
Education:	Business Administration Diploma Ryerson Polytechnical Institute, 1978
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2011-0277 EB-2010-0146 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 RP-1999-0001 EBRO 497 EBRO 495 EBRO 492 EBRO 490

EBRO 487
EBRO 485
EBRO 479
EBRO 473
EBRO 465

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
Appearances:	(Ontario Energy Board) EB-2012-0055 EB-2011-0354 EB-2011-0008

CURRICULUM VITAE OF
BARRY C. YUZWA

Experience: Enbridge Gas Distribution Inc.

Controller
2011

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

Appearances: (Ontario Energy Board)
EB-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0008

2012 EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. The 2012 Earnings Sharing amount included within Enbridge Gas Distribution Inc's. Fiscal 2012 year-end audited statements was $10.35 million, which agrees to the amount being requested for approval and clearance within this application. In order to meet year end timing obligations, estimates for elements impacting the accrual are sometimes required in lieu of complete or detailed analyses along with the rounding of various actual amounts into $millions for regulatory presentation. Following the year end close process however, completion of analyses are performed for elements where estimates were used along with rounding finalizations, in order to ensure the earnings sharing amount is accurate. If required and appropriate, an adjustment is made to the earnings sharing results, which ultimately is reflected in following year financial statements. The process followed is the same each year, which for Fiscal Years 2009, 2010, and 2011, led to adjustments to the earnings sharing amounts included within the earnings sharing applications, as compared to the year-end financial statements. In 2012, the process resulted in no change to the ESM accrual.

2. 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 within Exhibit B, Tab 1, Schedule 2.

3. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2007-0615 Board Approved Settlement Agreement (Ex. N1, T1, S1, 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 (ie., 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;
- 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 calculaton;

4. In the EB-2007-0615 Settlement Agreement the Parties acknowledge 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;
   - 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 (Ex. N1, T1, S1, p. 23).

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

6. 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 within 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.

Part A)

7. The level of utility income, $280.7 million (Line 19) divided by the level of utility rate base, $4,010.6 million (Line 24) generates a utility return on rate base of 6.999% (Line 25).

8. When compared to the Company's required rate of return of 6.620% (Line 26), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.379% (Line 27) on total rate base.

9. As shown in Lines 28 through 30, the sufficiency of 0.379% multiplied by the rate base of $4,010.6 million, produces a net over earnings or sufficiency of $15.20 million which from a pre-tax perspective, ($15.20 million divided by the reciprocal, 73.5%, of the corporate tax rate which is 26.5%) shows a $20.68 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)

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

11. The $328.2 million (Line 33) of utility income before income tax, less utility taxes of $47.5 million (Line 38), produces the $280.7 million of utility income used in part A) above (at Line 19).

12. In order to determine utility net income applicable to a deemed common equity percentage within rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $280.7 million utility income.

13. These reductions are shown at Lines 34, 35 and 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 $138.2 million, shown at Line 39.

14. The $138.2 million, divided by the deemed common equity level of $1,443.8 million (Line 40, calculated as 36% of the $4,010.6 million rate base) produces a return on equity of 9.570% (Line 42). When comparing the 9.570% achieved return on equity to the threshold ROE percentage of 8.52% (Line 41), which is the Board approved formula return on equity for 2012 of 7.52% plus the approved 100 basis point dead band, there is a sufficiency in ROE of 1.05% (Line 43).

15. The 1.05% multiplied by the common equity level of $1,443.8 million (Line 40) produces a net over earnings or sufficiency of $15.16 million which from a pre-tax perspective, ($15.16 million divided by the reciprocal, 73.5%, of the corporate tax rate) shows a $20.63 million total amount of over earnings to be shared equally

between ratepayers and the Company. Column 2 provides supporting evidence references.

Process Description

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

17. 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,

18. 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 within 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 shared savings mechanism,
- elimination of EGD share of transactional services, and
- elimination of EGD share of tax rate and rule changes.

19. 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 cost of capital information is found in Exhibit B, Tab 5.

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2012

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	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)	2,001.0
3.	Transportation Revenue	(Ex.B,T5,S2,P1,Col.1,line 2)	347.1
4.	Less Cost of Gas	(Ex.B,T5,S2,P1,Col.1,line 8)	1,314.1
5.	Gas Distribution Margin		1,034.0
6.	Transmission, Compr. and Storage Revenue	(Ex.B,T5,S2,P1,Col.1,line 3)	1.3
7.	Other Revenue	(Ex.B,T5,S2,P1,Col.1,line 4)	36.8
8.	Other Income	(Ex.B,T5,S2,P1,Col.1,line 6)	6.1
9.	Total - TC&S, Oth. Rev. & Inc.		44.2
10.	Operations, Maintenance & Administration	(Ex.B,T5,S2,P1,Col.1,line 9)	391.4
11.	Depreciation & amortization	(Ex.B,T5,S2,P1,Col.1,line 10)	292.9
12.	Fixed financing costs	(Ex.B,T5,S2,P1,Col.1,line 11)	2.0
13.	Debt redemption premium amortization	(Ex.B,T5,S2,P1,Col.1,line 12)	0.2
14.	Company share of IR agreement tax savings	(Ex.B,T5,S2,P1,Col.1,line 13)	25.3
15.	Municipal & capital taxes	(Ex.B,T5,S2,P1,Col.1,line 14)	38.2
16.	Total O&M, Depr., & other		750.0
17.	Utility Income before Income Tax	(line 5 + line 9 - line 16)	328.2
18.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	47.5
19.	**Utility Income**		**280.7**
20.	Gross plant	(Ex.B,T2,S1,P1,Col.1,line 1)	6,389.4
21.	Accumulated depreciation	(Ex.B,T2,S1,P1,Col.1,line 2)	(2,573.3)
22.	Net plant		3,816.1
23.	Working capital	(Ex.B,T2,S1,P1,Col.1,line 12)	194.5
24.	**Utility Rate Base**		**4,010.6**
25.	Indicated Return on Rate Base %	(line 19 / line 24)	6.999%
26.	Less: Required Rate of Return %	(Ex.B,T5,S1,P1,Col.4,line 6)	6.620%
27.	(Deficiency) / Sufficiency %		0.379%
28.	Net Earnings (Deficiency) / Sufficiency	(line 27 x line 24)	15.20
29.	Provision for Income Taxes		5.48
30.	Gross Earnings (Deficiency) / Sufficiency	(line 28 divide by 73.5%)	20.68
31.	**50% Earnings sharing to ratepayers**	(line 30 x 50%)	**10.34**
32.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
33.	Utility Income before Income Tax	(Ex.B,T5,S2,P1,Col.1,line 18)	328.2
34.	Less: Long Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 1)	138.6
35.	Less: Short Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 2)	1.5
36.	Less: Cost of Preferred Capital	(Ex.B,T5,S1,P1,Col.5,line 4)	2.4
37.	Net Income before Income Taxes		185.7
38.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	47.5
39.	Net Income Applicable to Common Equity	(line 37 - line 38)	138.2
40.	Common Equity	(Ex.B,T5,S1,P1,Col.1,line 5)	1,443.8
41.	Approved ROE %	(EB-2007-0615 for Earnings Sharing 7.52% + 100 bp)	8.520%
42.	Achieved Rate of Return on Equity %	(line 39 divide by line 40)	9.570%
43.	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.05%
44.	Net Earnings (Deficiency) / Sufficiency	(line40 x line 43)	15.16
45.	Provision for Income Taxes		5.47
46.	Gross Earnings (Deficiency) / Sufficiency	(line 44 divide by 73.5%)	20.63
47.	**50% Earnings sharing to ratepayers**	(line 46 x 50%)	**10.31**

EGD
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS
FOR FISCAL YEAR 2012

Line No.		Col. 1 2012 Actual Normalized $Millions	Col. 2 2007 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	2,001.0	2,369.1		
2.	Transportation revenue	347.1	748.8		
3.	Transmission, compression & storage	1.3	1.9		
4.	Gas costs	1,314.1	2,174.6		
5.	Distribution margin	1,035.3	945.2	90.1	a)
6.	Other revenue	36.8	34.3	2.5	b)
7.	Other income	6.1	0.2	5.9	c)
8.	O&M	391.4	326.2	(65.2)	d)
9.	Depreciation expense	292.9	227.3	(65.6)	e)
10.	Other expense	65.7	56.4	(9.3)	f)
11.	Income taxes	47.5	85.8	38.3	g)
12.	Utility Income	280.7	284.0	(3.3)	
13.	LTD & STD costs	140.1	165.8	25.7	h)
14.	Preference share costs	2.4	5.0	2.6	h)
15.	Return on Equity @ 8.52%[1] in 2012, 8.39% in 2007	123.0	113.2	(9.8)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	15.2	(0.0)	15.2	
17.	Provision for taxes on Earnings Over / (Under)	5.5	(0.0)	5.5	
18.	Gross Earnings Over / (Under)	20.7	(0.0)	20.7	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,443.8			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	138.2			
21.	EGD normalized Return on Equity	9.57%			

[1] 7.52% as per Board Approved formula using October 2011 consensus forecast, plus 100 basis points as per 2008 incentive regulation Board Approved agreement.

Witnesses: K. Culbert
R. Small

2012 Earnings Sharing Amount and Contributors

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 $90.1 million is mainly the result of the change in revenue derived from EGD's IR framework and formula where forecast cumulative 2012 IR formula revenue was an increase of $86.8 million from the base year DRR amount (beginning amount in 2008 was $753.2, ending amount in 2012 was $840.0, EB-2011-0277 Rate Order Appendix A), increases in DSM and Customer Care related Y-Factors versus 2007 Board approved levels and, significant 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 2012 QRAM's versus pricing embedded in 2007 approved rates. This results in a positive earnings impact.

b) The other revenue change of $2.5 million is an increase in service charge amounts, increased late payment penalty revenue and a decrease in other revenue. This results in a positive earnings impact.

c) The other income change of $5.9 million is mostly the result of the recognition of foregone late payment penalty revenue necessitated as a result of the Board GDAR amendments in relation to customer service rules, 3rd party use amounts of commodity by-product and other miscellaneous.

Witnesses: K. Culbert
R. Small

d) Utility O&M is $65.2 million above that of the 2007 approved level embedded in base rates used within the incentive regulation escalation formula. For a presentation of the details of utility O&M please see evidence at Exhibit B, Tab 4, Schedule 2. This results in a reduction in earnings.

e) The increase in depreciation expense of $65.6 million is mostly due to higher levels of property, plant, and equipment associated within customer growth and system improvement activities in each of 2008, 2009, 2010, 2011, and 2012, and the implementation of the new CIS system in 2009. The impact of increases in customer growth and system improvement P.P.& E. in 2008, 2009, 2010, and 2011 has a full year depreciation increase impact in 2012 while the increases relative to 2012 have a part year depreciation increase impact. The depreciation increases result in a reduction in earnings.

f) Other expenses increase of $9.3 million is the result of an increase in recognition of EGD's $25.3 million share of the IR agreement tax savings impact, an increase in fixed financing and debt redemption premium costs of $0.9 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 $7.7 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 earnings impact.

h) The interest cost of utility long, medium and short term debt and preference share costs changed by $28.3 million relative to 2007 approved levels as a result of lower overall average cost rates. This results in a positive earnings impact.

Witnesses: K. Culbert
R. Small

RECONCILIATION OF AUDITED EGDI
CONSOLIDATED INCOME TO UTILITY INCOME
2012 HISTORICAL YEAR

Line no.		Col. 1 Audited Consolidated Income ($millions)	Col. 2 Utility Income ($millions)	Col. 3 Difference ($millions)	Col. 4 Reference
1.	Gas commodity and distribution revenue	1,868.9	2,001.0	132.1	a)
2.	Transportation of gas for customers	345.4	347.1	1.7	b)
3.		2,214.3	2,348.1	133.8	
4.	Gas commodity and distribution costs	1,198.8	1,314.1	115.3	c)
5.	Gas distribution margin	1,015.5	1,034.0	18.5	
6.	Other revenue	201.5	44.2	(157.3)	d)
7.		1,217.0	1,078.2	(138.8)	
	Expenses				
8.	Operation and maintenance	448.9	391.4	(57.5)	e)
9.	Earnings sharing	10.4	-	(10.4)	f)
10.	Depreciation	320.0	292.9	(27.1)	g)
11.	Municipal and other taxes	40.0	38.2	(1.8)	h)
12.	Company share of IR agreement tax savings	-	25.3	25.3	i)
13.		819.3	747.8	(71.5)	
14.	Income before undernoted items	397.7	330.4	(67.3)	
15.	Financing income	62.7	-	(62.7)	j)
16.	Interest and financing expenses	(169.7)	(2.2)	167.5	k)
17.	Income before income taxes	290.7	328.2	37.5	
18.	Income taxes	(60.6)	(47.5)	13.1	l)
19.	Income (net) from discontinued operations	4.5	-	(4.5)	m)
20.	Net Income	234.6	280.7	46.1	

Witnesses: K. Culbert
R. Small

RECONCILIATION OF 2012
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
a)	1,868.9	**Consolidated gas commodity and distribution revenue**
	(34.3)	Amounts related to St. Lawrence Gas
	96.3	Normalization adjustment
	68.6	US GAAP adjustment elimination - deferral clearance adjustment
	1.6	Gazifere T-service regrouped to gas commodity and distribution revenue
	(0.1)	Rounding
	2,001.0	**Utility gas commodity and distribution revenue**
b)	345.4	**Consolidated transportation of gas for customers**
	(9.0)	Amounts related to St. Lawrence Gas
	12.2	Normalization adjustment
	(1.6)	Gazifere T-service regrouped to gas commodity and distribution revenue
	0.1	Rounding
	347.1	**Utility transportation of gas for customers**
c)	1,198.8	**Consolidated gas commodity and distribution costs**
	(29.4)	Elimination of amounts related to St. Lawrence Gas, unregulated storage
	76.8	Normalization adjustment
	67.9	US GAAP adjustment elimination
	1,314.1	**Utility gas commodity and distribution costs**

Witnesses: K. Culbert
R. Small

RECONCILIATION OF 2012
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
d)	201.5	**Consolidated other revenue**
	(22.8)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(13.8)	Open Bill O&M expenses regrouped against program revenues
	(4.0)	ABC administration and bad debt costs regrouped against program revenues from O&M
	(0.1)	ABC interest charges regrouped against program revenues
	5.8	Allowable interest during construction regrouped to revenues from interest and financing expenses
	(7.5)	Electric CDM costs regrouped against program revenues from O&M
	(88.7)	US GAAP adjustment elimination - OPEB cash vs accrual adjustment (TIACDA)
	(10.4)	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
	(0.1)	Elimination of the shareholder portion of net ex-franchise Open Bill revenues
	(1.5)	Elimination of Open Bill revenues to reflect the shareholder incentive
	(0.3)	Elimination of the shareholder portion of net electric CDM revenues
	(1.4)	Elimination of affiliate and 3rd party asset use revenue considered non-utility
	(2.5)	Elimination of net ABC revenue considered non-utility
	(0.1)	Elimination of interest income from investments not included in rate base
	(4.2)	Elimination of shareholder portion of incentive income associated with the SSMVA
	(5.8)	Elimination of allowable interest during construction
	(0.1)	Rounding
	44.2	**Utility other revenue**
e)	448.9	**Consolidated operation and maintenance**
	(11.7)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(13.8)	Open Bill expenses regrouped against program revenues
	(4.0)	ABC administration and bad debt costs regrouped against program revenues and eliminated
	(7.5)	Electric CDM expenses regrouped against program revenues
	0.9	Interest on security deposits added to utility O&M
	(1.0)	Elimination of donations
	(1.6)	Elimination of non-utility costs of supporting the ABC program
	(16.8)	Elimination of Corporate Cost Allocations above RCAM amount
	0.7	US GAAP Adjustment elimination - deferral clearance adjustment
	(2.4)	US GAAP Adjustment elimination - OPEB cash vs accrual adjustment
	(0.2)	Elimination of 2011 earnings sharing true-up amount within 2012 year end financials from utility income calculation
	(0.1)	Rounding
	391.4	**Utility operation and maintenance**
f)	10.4	**Consolidated earnings sharing**
	(10.4)	Elimination of 2012 earnings sharing amount within year end financials from utility income calculation
	-	**Utility earnings sharing**
g)	320.0	**Consolidated depreciation**
	(4.2)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects
	(22.5)	US GAAP adjustment for PPD amortization
	(0.2)	Elimination of depreciation on disallowed Mississauga Southern Link
	(0.2)	Elimination of depreciation related to shared assets
	292.9	**Utility depreciation**

Witnesses: K. Culbert
R. Small

RECONCILIATION OF 2012
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
h)	40.0	**Consolidated municipal and other taxes**
	(1.6)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(0.2)	Elimination of municipal taxes related to shared assets
	38.2	**Utility municipal and other taxes**
i)	-	**Consolidated IR agreement tax savings**
	25.3	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, EB-2011-0008, and EB-2013-0046.
	25.3	**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)	169.7	**Consolidated interest and financing expenses**
	(3.9)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(26.8)	Eliminate non-utility interest expense from the Board Approved financing transaction
	5.8	Allowable interest during construction regrouped to revenues and eliminated
	(0.1)	ABC interest charges regrouped against program revenues and eliminated
	(142.4)	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure
	(0.1)	Rounding
	2.2	**Utility interest and financing expenses**
l)	60.6	**Consolidated income taxes**
	(4.5)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(56.1)	Elimination of corporate income taxes
	47.5	Addition of income taxes calculated on a utility "stand-alone" basis
	47.5	**Utility income taxes**
m)	4.5	**Consolidated income from discontinued operations**
	(4.5)	Earnings attributable to discontinued solar operations
	-	**Utility income from discontinued operations**

Witnesses: K. Culbert
R. Small

UTILITY RATE BASE
COMPARISON OF 2012 HISTORICAL YEAR TO 2011 HISTORICAL YEAR

		Col. 1	Col. 2	Col. 3
Line No.		2012 Historical Year	2011 Historical Year	Difference
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	6,389.4	6,064.1	325.3
2.	Accumulated depreciation	(2,573.3)	(2,398.4)	(174.9)
3.	Net property, plant, and equipment	3,816.1	3,665.7	150.4
	Allowance for Working Capital			
4.	Accounts receivable merchandise finance plan	-	-	0.0
5.	Accounts receivable rebillable projects	1.9	1.6	0.3
6.	Materials and supplies	40.3	30.1	10.2
7.	Mortgages receivable	0.3	0.4	(0.1)
8.	Customer security deposits	(67.8)	(75.6)	7.8
9.	Prepaid expenses	1.2	1.5	(0.3)
10.	Gas in storage	229.5	337.6	(108.1)
11.	Working cash allowance	(10.9)	(4.3)	(6.6)
12.	Total Working Capital	194.5	291.3	(96.8)
13.	Utility Rate Base	4,010.6	3,957.0	53.6

Witnesses: K. Culbert
R. Small

UTILITY RATE BASE
COMPARISON OF 2011 HISTORICAL YEAR TO 2010 HISTORICAL YEAR

Line No.		Col. 1 2011 Historical Year	Col. 2 2010 Historical Year	Col. 3 Difference
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	6,064.1	5,807.2	256.9
2.	Accumulated depreciation	(2,398.4)	(2,235.7)	(162.7)
3.	Net property, plant, and equipment	3,665.7	3,571.5	94.2
	Allowance for Working Capital			
4.	Accounts receivable merchandise finance plan	-	-	0.0
5.	Accounts receivable rebillable projects	1.6	0.5	1.1
6.	Materials and supplies	30.1	24.1	6.0
7.	Mortgages receivable	0.4	0.6	(0.2)
8.	Customer security deposits	(75.6)	(67.1)	(8.5)
9.	Prepaid expenses	1.5	1.3	0.2
10.	Gas in storage	337.6	310.1	27.5
11.	Working cash allowance	(4.3)	(3.3)	(1.0)
12.	Total Working Capital	291.3	266.2	25.1
13.	Utility Rate Base	3,957.0	3,837.7	119.3

Witnesses: K. Culbert
R. Small

UTILITY PROPERTY, PLANT, AND EQUIPMENT
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2012 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	323.1	(115.2)	207.9
2.	Distribution plant	5,675.5	(2,319.9)	3,355.6
3.	General plant	398.1	(137.4)	260.7
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	6,397.2	(2,573.0)	3,824.2
6.	Plant held for future use	1.7	(1.1)	0.6
7.	Sub- total	6,398.9	(2,574.1)	3,824.8
8.	Affiliate Shared Assets Value	(9.5)	0.8	(8.2)
9.	Total property, plant, and equipment	6,389.4	(2,573.3)	3,816.1

Witnesses: K. Culbert
R. Small

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2012	Col. 5 Regulatory Adjustments	Col. 6 Utility Balance Dec.2012	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)	41.7	1.1	-	42.8	(1.0)	41.8	40.7
3.	Structures and improvements (452.00)	14.5	1.0	-	15.5	(0.1)	15.4	14.5
4.	Wells (453.00)	42.2	3.2	-	45.4	-	45.4	42.2
5.	Well equipment (454.00)	8.9	0.4	-	9.4	-	9.4	9.0
6.	Field Lines (455.00)	60.3	10.5	-	70.8	-	70.8	66.0
7.	Compressor equipment (456.00)	93.6	3.9	-	97.5	(0.5)	97.1	94.2
8.	Measuring and regulating equipment (457.00)	11.5	-	-	11.5	-	11.5	11.5
9.	Base pressure gas (458.00)	40.9	0.0	-	40.9	-	40.9	40.9
10.	Total	317.7	20.1	-	337.8	(1.5)	336.3	323.1

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2012	Col. 6 Regulatory Adjustments	Col. 7 Utility Balance Dec.2012	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(2.2)	(0.1)	-	0.1	(2.2)	-	(2.2)	(2.3)
2.	Land and gas storage rights (451.00)	(21.0)	(0.8)	-	-	(21.9)	-	(21.9)	(21.5)
3.	Structures and improvements (452.00)	(5.1)	(0.4)	-	-	(5.4)	0.1	(5.4)	(5.2)
4.	Wells (453.00)	(18.9)	(1.9)	-	0.1	(20.7)	-	(20.7)	(19.8)
5.	Well equipment (454.00)	(4.7)	(0.3)	-	-	(5.0)	-	(5.0)	(4.9)
6.	Field Lines (455.00)	(22.1)	(1.8)	-	0.8	(23.1)	-	(23.1)	(22.6)
7.	Compressor equipment (456.00)	(32.6)	(2.2)	-	-	(34.8)	0.2	(34.6)	(33.5)
8.	Measuring and regulating equipment (457.00)	(5.4)	(0.4)	-	-	(5.8)	-	(5.8)	(5.6)
9.	Total	(112.0)	(8.0)	-	1.1	(118.9)	0.2	(118.7)	(115.2)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2012	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2012	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	20.6	(0.0)	(1.5)	19.1	-	19.1	20.6
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	7.5	-	-	7.5	-	7.5	7.5
4.	Structures and improvements (472.00)	85.8	33.8	(0.5)	119.1	(0.3)	118.8	95.8
5.	Services, house reg & meter install. (473/474)	2,108.6	135.7	(29.1)	2,215.2	-	2,215.2	2,152.7
6.	NGV station compressors (476)	2.7	-	-	2.7	-	2.7	2.7
7.	Meters (478)	382.5	22.6	(8.9)	396.2	-	396.2	385.3
8.	Sub-total	2,607.6	192.0	(39.9)	2,759.8	(0.3)	2,759.4	2,664.5
9.	Mains (475)	2,616.9	151.2	(19.2)	2,748.9	(2.2)	2,746.7	2,675.9
10.	Measuring and regulating equip. (477)	328.3	24.2	(0.5)	352.0	(0.5)	351.5	335.1
11.	Sub-total	2,945.2	175.4	(19.7)	3,100.9	(2.7)	3,098.2	3,010.9
12.	Total	5,552.8	367.5	(59.6)	5,860.7	(3.1)	5,857.6	5,675.5

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2012	Col. 6 Regulatory Adjustment (Note 1)	Col. 7 Utility Balance Dec.2012	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(1.5)	(0.4)	-	-	(1.8)	-	(1.8)	(1.6)
2.	Structures and improvements (472.00)	(6.5)	(2.8)	0.5	0.2	(8.6)	0.1	(8.4)	(7.7)
3.	Services, house reg & meter install. (473/474)	(926.8)	(98.1)	29.1	16.7	(979.2)	-	(979.2)	(952.6)
4.	NGV station compressors (476)	(1.8)	(0.2)	-	-	(2.0)	-	(2.0)	(1.9)
5.	Meters (478)	(94.5)	(9.6)	8.9	(0.9)	(96.1)	-	(96.1)	(94.7)
6.	Mains (475)	(1,036.6)	(111.7)	19.2	10.7	(1,118.4)	1.5	(1,116.9)	(1,082.4)
7.	Measuring and regulating equip. (477)	(171.3)	(17.5)	0.5	0.4	(187.9)	0.5	(187.4)	(178.9)
8.	Total	(2,239.0)	(240.2)	58.1	27.1	(2,394.0)	2.1	(2,391.9)	(2,319.9)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2012	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2012	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	5.4	1.1	(1.5)	4.9	(0.2)	4.7	5.1
2.	Office furniture and equipment (483.00)	21.8	1.1	(6.5)	16.3	-	16.3	18.7
3.	Transportation equipment (484.00)	46.1	2.3	(0.8)	47.6	(0.1)	47.5	46.8
4.	NGV conversion kits (484.01)	8.1	0.4	-	8.5	-	8.5	8.3
5.	Heavy work equipment (485.00)	20.5	0.2	-	20.7	-	20.7	20.6
6.	Tools and work equipment (486.00)	35.9	1.7	-	37.6	-	37.6	36.4
7.	Rental equipment (487.70)	1.0	-	-	1.0	-	1.0	1.0
8.	NGV rental compressors (487.80)	3.7	-	-	3.7	-	3.7	3.7
9.	NGV cylinders (484.02 and 487.90)	2.4	0.1	-	2.5	-	2.5	2.4
10.	Communication structures & equip. (488)	3.0	-	-	3.0	-	3.0	3.0
11.	Computer equipment (490.00)	35.3	10.4	(3.5)	42.3	-	42.3	37.2
12.	Software Aquired/Developed (491.00)	90.0	26.2	(21.7)	94.5	-	94.5	87.8
13.	CIS (491.00)	127.1	-	-	127.1	-	127.1	127.1
14.	Total	400.2	43.5	(34.0)	409.7	(0.3)	409.4	398.1

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2012 ($Millions)	Col. 6 Regulatory Adjustment (Note 1) ($Millions)	Col. 7 Utility Balance Dec.2012 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(4.2)	(0.9)	1.5	-	(3.6)	0.1	(3.5)	(3.7)
2.	Office furniture and equipment (483.00)	(8.3)	(0.9)	6.5	-	(2.6)	-	(2.8)	(5.2)
3.	Transportation equipment (484.00)	(9.8)	(2.1)	0.8	(0.4)	(11.4)	0.1	(11.3)	(10.7)
4.	NGV conversion kits (484.01)	(4.8)	(0.2)	-	-	(5.0)	-	(5.0)	(4.9)
5.	Heavy work equipment (485.00)	(7.3)	(0.8)	-	-	(8.1)	-	(8.1)	(7.7)
6.	Tools and work equipment (486.00)	(14.1)	(1.1)	-	-	(15.3)	-	(15.3)	(14.7)
7.	Rental equipment (487.70)	(1.0)	(0.0)	-	-	(1.0)	-	(1.0)	(1.0)
8.	NGV rental compressors (487.80)	(2.3)	(0.3)	-	-	(2.6)	-	(2.6)	(2.4)
9.	NGV cylinders (484.02 and 487.90)	(1.6)	(0.1)	-	-	(1.7)	-	(1.7)	(1.6)
10.	Communication structures & equip. (488)	(2.2)	(0.1)	-	-	(2.2)	-	(2.2)	(2.2)
11.	Computer equipment (490.00)	(4.9)	(7.2)	3.5	-	(8.6)	-	(8.6)	(6.0)
12.	Software Aquired/Developed (491.00)	(40.1)	(18.2)	21.7	0.0	(36.6)	-	(36.6)	(42.4)
13.	CIS (491.00)	(28.6)	(12.7)	-	-	(41.3)	-	(41.3)	(35.0)
14.	Total	(129.2)	(44.4)	34.0	(0.3)	(139.9)	0.2	(139.7)	(137.4)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2012	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2012	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
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2012	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2012	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
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2012	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2012	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
2012 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2011	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2012	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2012	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.0)	(0.1)	-	-	(1.1)	-	(1.1)	(1.1)
2.	Total	(1.0)	(0.1)	-	-	(1.1)	-	(1.1)	(1.1)

Witnesses: K. Culbert
R. Small

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ACTUAL 2012 AND ACTUAL 2011

Item No.		Col. 1 Actuals 2012 ($Millions)	Col. 2 Actuals 2011 ($Millions)	Col. 3 2012 Over/(Under) 2011 ($Millions)
A.	Customer Related			
1.1.1	Sales Mains	65.3	72.1	(6.8)
1.1.2	Services	71.8	55.9	15.9
1.1.3	Meters and Regulation	14.7	7.6	7.1
1.1.4	Customer Related Distribution Plant	151.8	135.6	16.2
1.1.5	NGV Rental Equipment	0.2	-	0.2
1.1	TOTAL CUSTOMER RELATED CAPITAL	152.0	135.6	16.4
B.	System Improvements and Upgrades			
1.2.1	Mains - Relocations	13.0	15.5	(2.5)
1.2.2	- Replacement	49.1	54.6	(5.5)
1.2.3	- Reinforcement	37.5	9.8	27.7
1.2.4	Total Improvement Mains	99.6	79.8	19.8
1.2.5	Services - Relays	48.1	45.9	2.2
1.2.6	Regulators - Refits	11.3	5.6	5.7
1.2.7	Measurement and Regulation	17.1	11.4	5.7
1.2.8	Meters	20.0	17.8	2.3
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	196.1	160.5	35.6
C.	General and Other Plant			
1.3.1	Land, Structures and Improvements	18.0	20.9	(2.9)
1.3.2	Office Furniture and Equipment	1.4	5.1	(3.7)
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	3.1	7.4	(4.3)
1.3.4	Tools and Work Equipment	2.0	1.9	0.1
1.3.5	Computers and Communication Equipment	42.9	37.7	5.2
1.3	TOTAL GENERAL AND OTHER PLANT	67.4	73.0	(5.6)
D.	Underground Storage Plant	22.4	30.1	(7.7)
E.	TOTAL CAPITAL EXPENDITURES	437.8	399.2	38.6

Witnesses: L. Au
S. Qian

ACTUAL 2012 CAPITAL EXPENDITURE WORKSHEET

Item No.		Col. 1 Business as Usual ($Millions)	Col. 2 Safety and Integrity Initiatives ($Millions)	Col. 3 Leave to Construct Projects ($Millions)	Col. 4 Total Actual 2012 ($Millions)
A.	Customer Related				
1.1.1	Sales Mains	62.2		3.1	65.3
1.1.2	Services	71.8			71.8
1.1.3	Meters and Regulation	14.7			14.7
1.1.4	Customer Related Distribution Plant	148.7	-	3.1	151.8
1.1.5	NGV Rental Equipment	0.2			0.2
					-
1.1	TOTAL CUSTOMER RELATED CAPITAL	148.9	-	3.1	152.0
B.	System Improvements and Upgrades				
1.2.1	Mains - Relocations	13.0			13.0
1.2.2	- Replacement	45.9	3.2		49.1
1.2.3	- Reinforcement	21.5		16.0	37.5
1.2.4	Total Improvement Mains	80.4	3.2	16.0	99.6
1.2.5	Services - Relays	41.7	6.4		48.1
1.2.6	Regulators - Refits	11.3			11.3
1.2.7	Measurement and Regulation	17.1			17.1
1.2.8	Meters	20.0			20.0
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	170.5	9.6	16.0	196.1
C.	General and Other Plant				-
1.3.1	Land, Structures and Improvements	4.2	13.8		18.0
1.3.2	Office Furniture and Equipment	1.4			1.4
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	3.1			3.1
1.3.4	Tools and Work Equipment	2.0			2.0
1.3.5	Computers and Communication Equipment	42.9			42.9
1.3	TOTAL GENERAL AND OTHER PLANT	53.6	13.8	-	67.4
D.	Underground Storage Plant	22.4			22.4
E.	TOTAL CAPITAL EXPENDITURES	395.3	23.4	19.1	437.8
Project Details:					
2.1	Incremental Cast Iron Replacement		9.6		9.6
2.2	Technical Training Facility		13.8		13.8
3.1	York Energy Centre			2.8	2.8
3.2	Other Power Generation			0.3	0.3
3.3	GTA Reinforcement			7.8	7.8
3.4	Alliston Reinforcement			3.2	3.2
3.5	Angus Reinforcement			3.1	3.1
3.6	Ottawa Reinforcement			1.0	1.0
3.7	Scarborough Reinforcement			0.9	0.9
Sub total Additional Initiatives			23.4	19.1	42.5

Witnesses: L. Au
S. Qian

EXPLANATION OF MAJOR CHANGES

IN ACTUAL 2012 UTILITY CAPITAL EXPENDITURES
FROM ACTUAL 2011 UTILITY CAPITAL EXPENDITURES

2012 Actual Capital Expenditures were $437.8 million, which is $38.6 million or 9.7% more than the 2011 Actual of $399.2 million. The capital expenditure increase was primarily related to increased requirements for customer related and system improvements and upgrades expenditures. This was partially offset by decreased requirements for storage and general plant. The major categories showing significant variances are explained below:

Item No.

1.1.4 Customer Related Distribution Plant – Increase $16.2 Million

Increased expenditures were due to higher direct costs related to customer mix, more customers and unit costs ($22.8M). Indirect overheads increased by $10.1M due to increased direct costs as a result of increased activity and a higher level of indirect costs. The increase was partially offset by the completion of the York Energy power generation facility in 2011 ($16.7M).

1.2.4 Improvement Mains – Increase $19.8 Million

The increase is primarily due to an increased volume of reinforcement activity. Several large reinforcement projects are underway in 2012. These include: GTA Reinforcement ($7.8M), Alliston ($3.2M), Angus ($3.1M), Sheridan Gate By-Pass ($2.8M), Ottawa ($1.0M) and Scarborough ($0.9M). The remaining increase is related to increased indirect costs.

1.2.5 Service Relays – Increase $2.2 Million

The increase is primarily due to increased units and higher unit prices relative to 2011.

Witnesses: L. Au
S. Qian

1.2.6 Regulator Refits – Increase $5.7 Million

The increase is primarily due to increased unit activity and higher unit prices relative to 2011.

1.2.7 Measurement and Regulation – Increase $5.7 Million

The bulk of the increase ($4.3M) was due to the Ottawa gate station project which was planned for 2011 but was delayed to 2012. The increase also includes higher indirect costs.

1.2.8 Meters – Increase $2.3 Million

The increase reflects the timing of the purchases relative to 2011. There were more meter purchases in 2012 due to TC Module upgrade program which was legislated by Measurement Canada to be completed by the end of 2012.

C. General and Other Plant – Decrease $5.6 Million

General plant requirements decreased relative to 2011 due to the completion of the Distribution Training and Operations facility ($8.4M). Fleet requirements decreased by $4.3M. The overall decrease was partially offset by increased requirements for Computer equipment and software expenditures increased by $5.7M which was primarily due to software requirements.

D. Underground Storage Plant – Decrease $7.7 million

The 2011 storage plant expenditures included a large one time initiative. The Meter Run Upgrade project was $13.9M in 2011. The purpose of this project was to replace and upgrade all storage metering which was largely unchanged since 1964. The bulk of that project was constructed in 2011 which resulted in an approximately $8M decrease in 2012.

Witnesses: L. Au
S. Qian

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ACTUAL 2011 AND ACTUAL 2010

Item No.		Col. 1 Actuals 2011 ($Millions)	Col. 2 Actuals 2010 ($Millions)	Col. 3 2011 Over/(Under) 2010 ($Millions)
A.	Customer Related			
1.1.1	Sales Mains	72.1	46.7	25.4
1.1.2	Services	55.9	52.6	3.3
1.1.3	Meters and Regulation	7.6	8.3	(0.7)
1.1.4	Customer Related Distribution Plant	135.6	107.6	28.0
1.1.5	NGV Rental Equipment	-	0.2	(0.2)
1.1	TOTAL CUSTOMER RELATED CAPITAL	135.6	107.8	27.8
B.	System Improvements and Upgrades			
1.2.1	Mains - Relocations	15.5	13.2	2.3
1.2.2	- Replacement	54.6	55.7	(1.1)
1.2.3	- Reinforcement	9.8	14.0	(4.2)
1.2.4	Total Improvement Mains	79.8	82.9	(3.1)
1.2.5	Services - Relays	45.9	45.8	0.1
1.2.6	Regulators - Refits	5.6	6.4	(0.8)
1.2.7	Measurement and Regulation	11.4	10.3	1.1
1.2.8	Meters	17.8	13.1	4.7
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	160.5	158.5	2.0
C.	General and Other Plant			
1.3.1	Land, Structures and Improvements	20.9	14.0	6.9
1.3.2	Office Furniture and Equipment	5.1	1.9	3.2
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	7.4	6.5	0.9
1.3.4	Tools and Work Equipment	1.9	2.5	(0.6)
1.3.5	Computers and Communication Equipment	37.7	32.0	5.7
1.3	TOTAL GENERAL AND OTHER PLANT	73.0	56.9	16.1
D.	Underground Storage Plant	30.1	14.7	15.4
E.	Customer Information System (CIS)	-	(0.3)	0.3
F.	TOTAL CAPITAL EXPENDITURES	399.2	337.6	61.6

Witnesses: L. Au
S. Qian

ACTUAL 2011 CAPITAL EXPENDITURE WORKSHEET

Item No.		Col. 1 Business as Usual ($Millions)	Col. 2 Safety and Integrity Initiatives ($Millions)	Col. 3 Leave to Construct Projects ($Millions)	Col. 4 Total Actual 2011 ($Millions)
A.	Customer Related				
1.1.1	Sales Mains	52.0		20.1	72.1
1.1.2	Services	55.9			55.9
1.1.3	Meters and Regulation	7.6			7.6
1.1.4	Customer Related Distribution Plant	115.5	-	20.1	135.6
1.1.5	NGV Rental Equipment	-			-
					-
1.1	TOTAL CUSTOMER RELATED CAPITAL	115.5	-	20.1	135.6
B.	System Improvements and Upgrades				
1.2.1	Mains - Relocations	15.5			15.5
1.2.2	- Replacement	46.8	7.8		54.6
1.2.3	- Reinforcement	7.8		2.0	9.8
1.2.4	Total Improvement Mains	70.0	7.8	2.0	79.8
1.2.5	Services - Relays	34.9	11.0		45.9
1.2.6	Regulators - Refits	5.6			5.6
1.2.7	Measurement and Regulation	11.4			11.4
1.2.8	Meters	17.8			17.8
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	139.7	18.8	2.0	160.5
C.	General and Other Plant				-
1.3.1	Land, Structures and Improvements	4.7	16.2		20.9
1.3.2	Office Furniture and Equipment	5.1			5.1
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	7.4			7.4
1.3.4	Tools and Work Equipment	1.9			1.9
1.3.5	Computers and Communication Equipment	37.7			37.7
1.3	TOTAL GENERAL AND OTHER PLANT	56.8	16.2	-	73.0
D.	Underground Storage Plant	30.1			30.1
E.	Customer Information System (CIS)				-
F.	TOTAL CAPITAL EXPENDITURES	342.1	35.0	22.1	399.2

Project Details:

2.1 Incremental Cast Iron Replacement		18.8		18.8
2.2 Technical Training Facility		16.2		16.2
3.1 York Energy Centre			20.1	20.1
3.2 GTA Reinforcement			1.5	1.5
3.3 Alliston Reinforcement			0.5	0.5
Sub total Additional Initiatives		35.0	22.1	57.1

Witnesses: L. Au
S. Qian

EXPLANATION OF MAJOR CHANGES

IN ACTUAL 2011 UTILITY CAPITAL EXPENDITURES
FROM ACTUAL 2010 UTILITY CAPITAL EXPENDITURES

2011 Actual Capital Expenditures were $399.2 million, which is $61.6 million or 18.2% more than the 2010 Actual of $337.6 million. The capital expenditure increase was primarily related to increased requirements for customer related, general plant and storage expenditures. This was partially offset by decreased requirements for system improvements and upgrades. The major categories showing significant variances are explained below:

Item No.

1.1.4 Customer Related Distribution Plant – Increase $28.0 Million

The increase in customer related plant was primarily driven by the "Leave to Construct" York Energy power generation facility ($15.8M) completed in 2011. In addition, increased expenditures were due to higher direct costs related to customer mix ($7.8M). The remaining increase was due to a higher allocation of indirect overheads.

1.2.4 Improvement Mains – Decrease $3.1 Million

The decrease is mainly a reflection of lower allocation of indirect overheads which were prorated between system improvement and customer related direct capital expenditures.

1.2.7 Measurement and Regulation – Increase $1.1 Million

The increase was primarily due to more system regulation requirements relative to 2010. The increase was driven by more aggressive workload and increased material costs in 2011.

1.2.8 Meters – Increase $4.7 Million

The increase reflects the timing of meter purchases relative to 2010. There were more meter purchases in 2011 due to a ramping up of the TC Module upgrade program which was legislated by Measurement Canada to be completed by the end of 2012.

C. General and Other Plant – Increase $16.1 Million

Construction costs related to the Distribution Training and Operations facility accounted for $7.2M of the increase. Computer equipment expenditures increased by $5.7M which was primarily due to software requirements. Furniture requirements increase by $3.2M, primarily due to furniture required for the Distribution Training and Operations facility and other office expansions.

D. Underground Storage Plant – Increase $15.4 million

The increase in storage plant expenditures reflects the on-going efforts of several plant initiatives. The Meter Run Upgrade project was $13.9M. The purpose of this project was to replace and upgrade all storage metering which was largely unchanged since 1964. The increase also included a compliance related project ($2.1M) mandated by the Ministry of Environment for noise emission standards.

Witnesses: L. Au
S. Qian

UTILITY OPERATING REVENUE
2012 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	1,904.7	96.3	2,001.0
2.	Transportation of gas	334.9	12.2	347.1
3.	Transmission, compression & storage	1.3	-	1.3
4.	Other operating revenue	36.8	-	36.8
5.	Other income	6.1	-	6.1
6.	Total operating revenue	2,283.8	108.5	2,392.3

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2012 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	96.3	Gas sales Adjustment to gas sales revenue required to reflect normal weather.
2.	12.2	Transportation of gas Adjustment to gas transportation revenue required to reflect normal weather.

UTILITY REVENUE
2012 HISTORICAL YEAR

Line No.		Col. 1 EGDI Ont. Corporate Revenue ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Revenue ($Millions)
1.	Residential	1,170.0	68.6	1,238.6
2.	Commercial	570.7	-	570.7
3.	Industrial	70.6	-	70.6
4.	Wholesale	24.8	-	24.8
5.	Gas sales	1,836.1	68.6	1,904.7
6.	Transportation of gas	334.9	-	334.9
7.	Transmission, compression & storage	1.3	-	1.3
8.	Service charges & DPAC	12.7	-	12.7
9.	Rent from NGV rentals	0.4	-	0.4
10.	Late payment penalties	10.1	-	10.1
11.	Transactional services	18.4	(10.4)	8.0
12.	Open bill revenue	6.8	(1.4)	5.4
13.	Dow Moore recovery	0.2	-	0.2
14.	Affiliate asset use revenue	0.1	(0.1)	-
15.	ABC T-service (net)	2.5	(2.5)	-
16.	Other operating revenue	51.2	(14.4)	36.8
17.	Income from investments	0.1	(0.1)	-
18.	Interest during construction	5.8	(5.8)	-
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	7.2	(7.2)	-
23.	Miscellaneous	127.2	(120.9)	6.3
24.	Dividend income	62.7	(62.7)	-
25.	Profit on sale of property	(0.2)	-	(0.2)
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	189.7	(183.6)	6.1
28.	Total revenue	2,420.4	(136.6)	2,283.8

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2012 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	68.6	Residential Gas Sales	
		US GAAP adjustment elimination - deferral & variance clearance recognition	68.6
			68.6
11.	(10.4)	Transactional services	
		To adjust transactional services to the base amount included in approved rates. Ratepayer and shareholder amounts above the base are treated outside of utility results and returns.	
12.	(1.4)	Open bill revenue	
		To eliminate the shareholder portion of OBSDA and OBAVA write-off.	0.2
		To eliminate net ex-franchise revenues to be shared equally between ratepayers and shareholders.	(0.1)
		To eliminate the Open Bill shareholder incentive.	(1.5)
			(1.4)
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.	(2.5)	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
2012 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
17.	(0.1)	Income from investments	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(5.8)	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.	(120.9)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas, unregulated storage and solar divisions.	(27.7)
		To eliminate Electric CDM net revenues. Ratepayer amounts will be transferred to the 2012 EPESDA and shareholder amounts are eliminated from utility results.	(0.3)
		US GAAP adjustment elimination - OPEB cash vs accrual adjustment	(88.7)
		To eliminate the shareholders' incentive income associated with the calculation of the SSMVA.	(4.2)
			(120.9)
24.	(62.7)	Dividend income	
		To eliminate non-utility inter-company dividend income.	-
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	(62.7)
			(62.7)

Witnesses: K. Culbert
R. Small

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2012 ACTUAL AND 2012 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2012 Actual	Col. 2 2012 Board Approved Budget	Col. 3 2012 Actual Over (Under) 2012 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 531.8	3 693.2	(161.4)
1.1.2	Rate 1 - T-Service	693.6	890.1	(196.5)
1.1	Total Rate 1	4 225.4	4 583.3	(357.9)
1.2.1	Rate 6 - Sales	2 232.4	2 620.6	(388.2)
1.2.2	Rate 6 - T-Service	1 984.4	2 151.6	(167.2)
1.2	Total Rate 6	4 216.8	4 772.2	(555.4)
1.3.1	Rate 9 - Sales	0.6	1.0	(0.4)
1.3.2	Rate 9 - T-Service	0.1	0.2	(0.1)
1.3	Total Rate 9	0.7	1.2	(0.5)
1.	Total General Service Sales & T-Service	8 442.9	9 356.7	(913.8)
Contract Sales				
2.1	Rate 100	1.5	0.0	1.5
2.2	Rate 110	88.2	64.3	23.9
2.3	Rate 115	0.9	0.0	0.9
2.4	Rate 135	1.2	0.6	0.6
2.5	Rate 145	22.7	21.4	1.3
2.6	Rate 170	45.1	49.7	(4.6)
2.7	Rate 200	164.6	162.2	2.4
2.	Total Contract Sales	324.2	298.2	26.0
Contract T-Service				
3.1	Rate 100	2.2	0.0	2.2
3.2	Rate 110	556.9	423.8	133.1
3.3	Rate 115	504.7	532.5	(27.8)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	55.3	54.6	0.7
3.6	Rate 145	140.7	133.0	7.7
3.7	Rate 170	442.8	470.3	(27.5)
3.8	Rate 300	29.6	31.0	(1.4)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 732.2	1 645.2	87.0
4.	Total Contract Sales & T-Service	2 056.4	1 943.4	113.0
5.	Total	10 499.3	11 300.1	(800.8)

* There is no distribution volume for Rate 125 customers.

Witnesses: C. Ho
S. Riccio

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2012 ACTUAL AND 2012 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2012 Actual	Col. 2 2012 Board Approved Budget	Col. 3 2012 Actual Over (Under) 2012 Budget (1-2)	Col. 4 2012* Adjustments	Col. 5 2012 Actual Over (Under) 2012 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	3 531.8	3 693.2	(161.4)	347.7	186.3
1.1.2	Rate 1 - T-Service	693.6	890.1	(196.5)	69.8	(126.7)
1.1	Total Rate 1	4 225.4	4 583.3	(357.9)	417.5	59.6
1.2.1	Rate 6 - Sales	2 232.4	2 620.6	(388.2)	236.2	(152.0)
1.2.2	Rate 6 - T-Service	1 984.4	2 151.6	(167.2)	162.5	(4.7)
1.2	Total Rate 6	4 216.8	4 772.2	(555.4)	398.7	(156.7)
1.3.1	Rate 9 - Sales	0.6	1.0	(0.4)	0.0	(0.4)
1.3.2	Rate 9 - T-Service	0.1	0.2	(0.1)	0.0	(0.1)
1.3	Total Rate 9	0.7	1.2	(0.5)	0.0	(0.5)
1.	Total General Service Sales & T-Service	8 442.9	9 356.7	(913.8)	816.2	(97.6)
Contract Sales						
2.1	Rate 100	1.5	0.0	1.5	0.1	1.6
2.2	Rate 110	88.2	64.3	23.9	0.2	24.1
2.3	Rate 115	0.9	0.0	0.9	0.0	0.9
2.4	Rate 135	1.2	0.6	0.6	0.0	0.6
2.5	Rate 145	22.7	21.4	1.3	0.6	1.9
2.6	Rate 170	45.1	49.7	(4.6)	0.5	(4.1)
2.7	Rate 200	164.6	162.2	2.4	0.5	2.9
2.	Total Contract Sales	324.2	298.2	26.0	1.9	27.9
Contract T-Service						
3.1	Rate 100	2.2	0.0	2.2	0.2	2.4
3.2	Rate 110	556.9	423.8	133.1	1.7	134.8
3.3	Rate 115	504.7	532.5	(27.8)	0.5	(27.3)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	55.3	54.6	0.7	0.0	0.7
3.6	Rate 145	140.7	133.0	7.7	4.1	11.8
3.7	Rate 170	442.8	470.3	(27.5)	7.8	(19.7)
3.8	Rate 300	29.6	31.0	(1.4)	0.0	(1.4)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 732.2	1 645.2	87.0	14.3	101.3
4.	Total Contract Sales & T-Service	2 056.4	1 943.4	113.0	16.2	129.2
5.	Total	10 499.3	11 300.1	(800.8)	832.4	31.6

*Note: Weather normalization adjustments have been made to the 2012 Actual utilizing the 2012 Board Approved Budget Degree Days in order to place the two years on a comparable basis.

Witnesses: C. Ho
S. Riccio

The principal reasons for the variances contributing to the weather normalized increase of 31.6 10^6m^3 in the 2012 Actual over the 2012 Board Approved Budget are as follows:

1. The volumetric increase of 59.6 10^6m^3 in Rate 1 was due to a favourable customer variance of 50.8 10^6m^3 and a higher average use per customer totalling 8.8 10^6m^3;

2. The volumetric decrease of 156.7 10^6m^3 in Rate 6 was due to a lower average use per customer totaling 173.5 10^6m^3; partially offset by a favourable customer variance of 16.8 10^6m^3;

3. The volumetric decrease of 0.5 10^6m^3 in Rate 9 was due to a lower average use per station totalling 0.4 10^6m^3 and the loss of one station of 0.1 10^6m^3;

4. The volumetric increase for Contract Sales and T-Service of 129.2 10^6m^3 was due to increases in the industrial sector of 79.2 10^6m^3, the commercial sector of 38.4 10^6m^3, the apartment sector of 8.7 10^6m^3 and Rate 200 of 2.9 10^6m^3. The increase was primarily attributable to lower gas prices than budgeted and improved business conditions, leading to production line increases and plant expansion.

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2012 HISTORICAL YEAR AND 2012 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2012 Actual	Col. 2 2012 Board Approved Budget	Col. 3 2012 Actual Over (Under) 2012 Budget (1-2)	Col. 4 2012* Adjustments	Col. 5 2012 Actual Over (Under) 2012 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	1 238.3	1 333.0	(94.7)	86.2	(8.5)
1.1.2	Rate 1 - T-Service	139.6	168.1	(28.5)	6.8	(21.7)
1.1	Total Rate 1	1 377.9	1 501.1	(123.2)	93.0	(30.2)
1.2.1	Rate 6 - Sales	612.5	751.7	(139.2)	53.8	(85.4)
1.2.2	Rate 6 - T-Service	153.8	164.1	(10.3)	11.8	1.5
1.2	Total Rate 6	766.3	915.8	(149.5)	65.6	(83.9)
1.3.1	Rate 9 - Sales	0.2	0.3	(0.1)	0.0	(0.1)
1.3.2	Rate 9 - T-Service	0.0 **	0.0 **	0.0 **	0.0	0.0 **
1.3	Total Rate 9	0.2	0.3	(0.1)	0.0	(0.1)
1.	Total General Service Sales & T-Service	2 144.4	2 417.2	(272.8)	158.6	(114.2)
Contract Sales						
2.1	Rate 100	0.3	0.0	0.3	0.0 **	0.3
2.2	Rate 110	15.4	13.9	1.5	0.0 **	1.5
2.3	Rate 115	0.3	0.0	0.3	0.0	0.3
2.4	Rate 135	0.2	0.1	0.1	0.0	0.1
2.5	Rate 145	4.4	4.5	(0.1)	0.1	0.0 **
2.6	Rate 170	8.2	9.4	(1.2)	0.1	(1.1)
2.7	Rate 200	24.8	28.5	(3.7)	0.1	(3.6)
2.	Total Contract Sales	53.6	56.4	(2.8)	0.3	(2.5)
Contract T-Service						
3.1	Rate 100	0.1	0.0	0.1	0.0 **	0.1
3.2	Rate 110	16.9	15.0	1.9	0.0 **	1.9
3.3	Rate 115	6.5	7.1	(0.6)	0.0 **	(0.6)
3.4	Rate 125	10.5	9.7	0.8	0.0 ***	0.8
3.5	Rate 135	2.3	1.6	0.7	0.0	0.7
3.6	Rate 145	4.8	3.6	1.2	0.0 **	1.2
3.7	Rate 170	4.9	(0.8)	5.7	0.0 **	5.7
3.8	Rate 300	0.4	0.4	0.0 **	0.0	0.0 **
3.9	Rate 315	0.4	0.0	0.4	0.0	0.4
3.	Total Contract T-Service	46.8	36.6	10.2	0.0	10.2
4.	Total Contract Sales & T-Service	100.4	93.0	7.4	0.3	7.7
5.	Total	2 244.8	2 510.2	(265.4)	158.9	(106.5)

* Note: Weather normalization adjustments have been made to the 2012 Actuals utilizing the 2012 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

Witnesses: C. Ho
S. Riccio

1. Gas sales and transportation of gas revenues for the 2012 Test Year Budget were developed on the basis of EB-2011-0277 rates.

2. The principal reasons for the variances contributing to the decrease of $265.4 million in the 2012 Actual under the 2012 Budget are as follows:

3. Gas Sales - Decrease of $236.8 Million

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

Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

4. Transportation of Gas - Decrease of $28.6 Million

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

Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2012 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	1 537 221	3 531.8	1 238.3
1.1.2	Rate 1 - T-Service	299 046	693.6	139.6
1.1	Total Rate 1	1 836 267	4 225.4	1 377.9
1.2.1	Rate 6 - Sales	128 972	2 232.4	612.5
1.2.2	Rate 6 - T-Service	29 227	1 984.4	153.8
1.2	Total Rate 6	158 199	4 216.8	766.3
1.3.1	Rate 9 - Sales	7	0.6	0.2
1.3.2	Rate 9 - T-Service	1	0.1	0.0 **
1.3	Total Rate 9	8	0.7	0.2
1.	Total General Service Sales & T-Service	1 994 474	8 442.9	2 144.4
Contract Sales				
2.1	Rate 100	3	1.5	0.3
2.2	Rate 110	37	88.2	15.4
2.3	Rate 115	1	0.9	0.3
2.4	Rate 135	2	1.2	0.2
2.5	Rate 145	12	22.7	4.4
2.6	Rate 170	6	45.1	8.2
2.7	Rate 200	1	164.6	24.8
2.	Total Contract Sales	62	324.2	53.6
Contract T-Service				
3.1	Rate 100	4	2.2	0.1
3.2	Rate 110	163	556.9	16.9
3.3	Rate 115	26	504.7	6.5
3.4	Rate 125	4	0.0 *	10.5
3.5	Rate 135	37	55.3	2.3
3.6	Rate 145	98	140.7	4.8
3.7	Rate 170	30	442.8	4.9
3.8	Rate 300	5	29.6	0.4
3.9	Rate 315	0	0.0	0.4
3.	Total Contract T-Service	367	1 732.2	46.8
4.	Total Contract Sales & T-Service	429	2 056.4	100.4
5.	Total	1 994 903	10 499.3	2 244.8

* There is no distribution volume for Rate 125 customers.

** Less than $50,000.

Witnesses: C. Ho
S. Riccio

ENBRIDGE GAS DISTRIBUTION
DETAILS OF OTHER REVENUE AND OTHER INCOME
2012 ACTUAL AND 2011 ACTUAL

Item No.		Col. 1 2012 Actual ($Millions)	Col. 2 2011 Actual ($Millions)	Col. 3 2012 Actual Over/(Under) 2011 Actual ($Millions)
1.1	Service Charges & DPAC	12.7	13.2	(0.5)
1.2	Rental Revenue - NGV Program	0.4	0.5	(0.1)
1.3	Late Payment Penalties	10.1	13.2	(3.1)
1.4	Dow Moore Recovery	0.2	0.3	(0.1)
1.5	Transactional Services (net)	8.0	8.0	-
1.6	Miscellaneous	6.1	0.8	5.3
1.7	Open Bill Revenue	5.4	5.4	-
1.8	Total Other Revenue	42.9	41.4	1.5

Witnesses: R. Lei
S. Qian

ENBRIDGE GAS DISTRIBUTION
DETAILS OF OTHER REVENUE AND OTHER INCOME
2011 ACTUAL AND 2010 ACTUAL

		Col. 1	Col. 2	Col. 3
Item No.		2011 Actual ($Millions)	2010 Actual ($Millions)	2011 Actual Over/(Under) 2010 Actual ($Millions)
1.1	Service Charges & DPAC	13.2	13.0	0.2
1.2	Rental Revenue - NGV Program	0.5	0.8	(0.3)
1.3	Late Payment Penalties	13.2	13.1	0.1
1.4	Dow Moore Recovery	0.3	0.2	0.1
1.5	Transactional Services (net)	8.0	8.0	-
1.6	Ontario Power Authority Program Revenue *	-	11.7	(11.7)
1.7	Miscellaneous	0.8	1.6	(0.8)
1.8	Open Bill Revenue	5.4	5.4	-
1.9	Total Other Revenue	41.4	53.8	(12.4)

Note: The 2011 Ontario Power Authority Program Revenue reflects the ratepayer share of the net revenue associated within the Electric Program Earnings Sharing Account rather than in the ESMDA as a result of the 2010 Earnings Sharing Agreement.

Witnesses: R. Lei
S. Qian

COST OF SERVICE
2012 HISTORICAL YEAR

Line No.		Col. 1 Utility Costs and Expenses	Col. 2 Adjustments	Col. 3 Adjusted Utility Costs and Expenses
		($Millions)	($Millions)	($Millions)
1.	Gas costs	1,237.3	76.8	1,314.1
2.	Operation and maintenance	391.4	-	391.4
3.	Depreciation and amortization expense	292.9	-	292.9
4.	Fixed financing costs	2.0	-	2.0
5.	Debt redemption premium amortization	0.2	-	0.2
6.	Company share of IR agreement tax savings	25.3	-	25.3
7.	Municipal and other taxes	38.2	-	38.2
8.	Operating costs	1,987.3	76.8	2,064.1
9.	Income tax expense			47.5
10.	Cost of service			2,111.6

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2011 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
1.	76.8	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
2012 HISTORICAL YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	328.2	328.2	
	Add			
2.	Depreciation and amortization	292.9	292.9	
3.	Other	-	-	
4.	Other non-deductible items	4.2	4.2	
5	Total Add Back	297.1	297.1	
6.	Sub-total	625.3	625.3	
	Deduct			
7.	Capital cost allowance	246.0	246.0	
8.	Items capitalized for regulatory purposes	56.9	56.9	
9.	Deduction for "grossed up" Part VI.1 tax	2.9	2.9	
10.	Amortization of share/debenture issue expense	3.8	3.8	
11.	Amortization of cumulative eligible capital	0.4	0.4	
12	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Profit on sale of assets	(0.2)	(0.2)	
14.	Total Deduction	309.9	309.9	
15	Taxable income	315.4	315.4	
16.	Income tax rates	15.00%	11.50%	
17.	Provision	47.3	36.3	83.6
18.	Part VI.1 tax			1.0
19.	Investment tax credit			-
20.	Total taxes excluding interest shield			84.6
	Tax shield on interest expense			
21.	Rate base	4,010.6		
22.	Return component of debt	3.49%		
23.	Interest expense	140.0		
24.	Combined tax rate	26.500%		
25	Income tax credit			(37.1)
26	Total utility income taxes			47.5

Witnesses: K. Culbert
R. Small

COST OF SERVICE
2012 HISTORICAL YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,169.4	67.9	1,237.3
2.	Operation and maintenance	422.2	(30.8)	391.4
3.	Depreciation	260.4	(0.4)	260.0
4.	Amortization	32.9	-	32.9
5.	Depreciation and amortization	293.3	(0.4)	292.9
6.	Fixed financing costs	2.0	-	2.0
7.	Debt redemption premium amortization	0.2	-	0.2
8.	Company share of IR agreement tax savings	-	25.3	25.3
9.	Municipal and other taxes	38.4	(0.2)	38.2
10.	Capital taxes	-	-	-
11.	Municipal and other taxes	38.4	(0.2)	38.2
12.	Interest on long-term debt	135.4	(135.4)	-
13.	Amortization of preference share issue costs and debt discount and expense	3.8	(3.8)	-
14.	Interest and financing amortization	139.2	(139.2)	-
15.	Interest on short-term debt	6.5	(6.5)	-
16.	Interest due affiliates	26.8	(26.8)	-
17.	Other interest expense	33.3	(33.3)	-
18.	Total operating costs	2,098.0	(110.7)	1,987.3
19.	Current taxes	36.8	(36.8)	-
20.	Deferred taxes	21.9	(21.9)	-
21.	Income tax expense	58.7	(58.7)	-
22.	Cost of service	2,156.7	(169.4)	1,987.3

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2012 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	67.9	Gas Costs	
		US GAAP adjustment elimination, deferral & variance clearance recognition	
2.	(30.8)	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.	0.9
		To eliminate donations (EBRO 490).	(1.0)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.6)
		To eliminate Corporate Cost allocations above RCAM amount.	(16.8)
		US GAAP adjustment eliminations	
		- deferral clearance recognition	0.7
		- OPEB cash vs accrual adjustment	(2.4)
		To eliminate ESM amounts contained in the Corporate financials	(10.6)
			(30.8)
3.	(0.4)	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).	(0.2)
			(0.4)
8.	25.3	Company share of IR agreement tax savings	
		To reflect the impact of the shareholder portion of agreed tax savings on utility income. (EB-2011-0277, Ex.C.T1.S4.Col 5,line 62)	
9.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2012 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
12.	(135.4)	Interest on long-term debt Expense of capital.
13.	(3.8)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
15.	(6.5)	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.	(36.8)	Income taxes - current Income tax expense related to corporate earnings.
20.	(21.9)	Income taxes - deferred Income tax expense related to corporate earnings.

Witnesses: K. Culbert
R. Small

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2012 HISTORICAL YEAR

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2012	UCC Carry Forward
1	1,940,147,810	0	150,000	75,000	4.00%	(77,608,912)	1,862,688,898
51	1,036,509,744	358,263,693	0	179,131,847	6.00%	(72,938,495)	1,321,834,942
2	129,241,472	0	0	0	6.00%	(7,754,488)	121,486,984
6	15,166	0	0	0	10.00%	(1,517)	13,649
8	11,891,543	1,060,394	(845,000)	107,697	20.00%	(2,399,848)	9,707,089
10	22,151,429	4,653,763	(256,667)	2,198,548	30.00%	(7,304,993)	19,243,532
12	15,410,892	29,912,077	0	14,956,039	100.00%	(30,366,931)	14,956,039
12	30,043,165	0	0	0	100.00%	(30,043,165)	-
17	35,201	0	0	0	8.00%	(2,816)	32,385
38	5,067,908	208,562	(50,000)	79,281	30.00%	(1,544,157)	3,682,313
41	29,310,729	8,552,253	54,000	4,303,127	25.00%	(8,403,464)	29,513,518
13	1,478,826	1,085,065	0	542,533	0.00%	(249,000)	2,314,891
3	249,178	0	0	0	5.00%	(12,459)	236,719
45	890,449	0	0	0	45.00%	(400,702)	489,747
50	7,943,625	10,434,123	0	5,217,062	55.00%	(7,238,378)	11,139,370
52	0	0	0	0	100.00%	-	0
Total	3,230,387,138	414,169,930	(947,667)	206,611,132		(246,269,325)	3,397,340,076

Non-utility and shared asset eliminations	291,286
Utility Federal CCA	(245,978,039)

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 F2012	UCC Carry Forward
1	1,940,147,810	0	150,000	75,000	4.00%	(77,608,912)	1,862,688,898
51	1,036,509,744	358,263,693	0	179,131,847	6.00%	(72,938,495)	1,321,834,942
2	129,241,472	0	0	0	6.00%	(7,754,488)	121,486,984
6	15,166	0	0	0	10.00%	(1,517)	13,649
8	11,891,543	1,060,394	(845,000)	107,697	20.00%	(2,399,848)	9,707,089
10	22,151,429	4,653,763	(256,667)	2,198,548	30.00%	(7,304,993)	19,243,532
12	15,410,892	29,912,077	0	14,956,039	100.00%	(30,366,931)	14,956,039
12	30,043,165	0	0	0	100.00%	(30,043,165)	-
17	35,201	0	0	0	8.00%	(2,816)	32,385
38	5,067,908	208,562	(50,000)	79,281	30.00%	(1,544,157)	3,682,313
41	29,310,729	8,552,253	54,000	4,303,127	25.00%	(8,403,464)	29,513,518
13	1,478,826	1,085,065	0	542,533	0.00%	(249,000)	2,314,891
3	249,178	0	0	0	5.00%	(12,459)	236,719
45	890,449	0	0	0	45.00%	(400,702)	489,747
50	7,943,625	10,434,123	0	5,217,062	55.00%	(7,238,378)	11,139,370
52	0	0	0	0	100.00%	-	-
Total	3,230,387,138	414,169,930	(947,667)	206,611,132		(246,269,325)	3,397,340,076

Non-utility and shared asset eliminations	291,286
Utility Provincial CCA and UCC	(245,978,039)

Witnesses: K. Culbert
R. Small

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAINTENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2012

Line No.	Particulars ($ 000's)	Col. 1 Actual 2012	Col. 2 Actual 2011	Col. 3 Actual 2010	Col. 4 Actual 2009	Col. 5 Actual 2008	Col. 6 2012 Actual Over/(Under) 2011 Actual	Col. 7 OEB Approved 2007 Utility O&M
1.	Finance	$ 6,956	$ 6,196	$ 6,016	$ 5,981	$ 5,843	$ 760	$ 8,380
2.	Risk Management	569	2,459	2,141	2,865	1,695	(1,890)	1,986
3.	Customer Care Service Charges	67,487	64,190	68,742	82,042	84,583	3,297	83,493
4.	Customer Care Internal Costs	9,600	7,360	9,222	7,868	9,679	2,239	7,302
5.	Provision for Uncollectibles	9,459	21,542	11,500	17,855	16,660	(12,083)	15,105
6.	Gas Supply and GTA Project	3,990	4,246	3,999	3,661	3,794	(256)	3,754
7.	Legal and Corporate Security	5,186	4,146	1,407	1,170	1,147	1,039	1,207
8.	Operations	65,987	58,104	58,664	52,569	50,878	7,883	51,902
9.	Information Technology	33,158	30,893	30,398	22,695	21,247	2,264	21,790
10.	Business Development & Customer Strategy (excluding DSM)	14,560	15,631	18,567	14,255	13,364	(1,070)	19,118
11.	Human Resources (excluding benefits)	23,554	20,031	15,127	14,568	13,272	3,522	13,059
12.	Benefits	45,943	27,488	27,335	26,241	24,597	18,455	21,405
13.	Pipeline Integrity and Engineering	37,541	30,786	27,233	23,768	22,385	6,755	20,811
14.	Regulatory, Public and Government Affairs	16,024	14,892	15,171	13,497	13,297	1,132	15,904
15.	Non Departmental Expenses	31,624	31,130	25,822	31,332	30,258	494	18,307
16.	Corporate Cost Allocations (including direct costs)	48,446	43,440	36,692	34,266	32,166	5,006	18,100
17.	Total	420,082	382,534	358,036	354,633	344,866	37,548	321,624
18.	Capitalization (A&G)	(32,457)	(24,482)	(24,330)	(23,902)	(21,643)	(7,975)	(17,424)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	387,625	358,052	333,706	330,731	323,223	29,573	304,200
20.	Demand Side Management Programs (DSM)	28,100	26,708	25,468	24,255	23,100	1,392	22,000
21.	Total Net Utility Operating and Maintenance Expense	$ 415,725	$ 384,760	$ 359,174	$ 354,986	$ 346,323	$ 30,965	$ 326,200
22.	Regulatory Adjustments							
23.	To eliminate Corporate Cost Allocations above RCAM	(16,836)	(16,725)	(12,428)	(13,100)	(13,066)	(111)	
24.	To eliminate CIS fees above Customer Care settlement agreement	-	-	-	(4,900)	(9,811)	-	
25.	To eliminate Conservation Services	(7,490)	(7,292)	-	-	-	(198)	
26.	2010 ESM disallowance	-	-	(500)	-	-	-	
27.	Incremental O&M Allocated to Unregulated Storage	-	(233)	-	-	-	233	
28.	Total Adjustments	(24,326)	(24,249)	(12,928)	(18,000)	(22,877)	(76)	
29.	Utility O&M	$ 391,400	$ 360,511	$ 346,246	$ 336,986	$ 323,446	$ 30,889	

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations, and other utility adjustments.
2) Historical years including the 2007 OEB approved budget have been restated based on the 2012 organization structure.

Witnesses: R. Lei
S. Qian

EXPLANATION OF MAJOR CHANGES
ACTUAL 2012 O&M EXPENSES COMPARED TO ACTUAL 2011 O&M EXPENSES

The 2012 Actual Utility O&M was $391.4 million, which was $30.8 million higher than the 2011 Actual Utility O&M of $360.5 million. The increase was primarily driven by higher pension costs, integrity management spend principally driven by in-line inspections (“ILI”) of pipe, contractor costs, corporate cost allocation costs, and severances. These were partially offset by lower provision for uncollectibles and higher A&G capitalization costs.

Line No:

2. Risk Management decreased by $1.9 million resulting from lower claims and settlements.

3. Customer Care Service Charges increased by $3.3 million due to higher call centre service cost, higher credit and collection costs, and higher billing costs.

4. Customer Care Internal Costs were higher by $2.2 million as a result of higher contract labour costs and staff additions.

5. Provision for Uncollectibles decreased by $12.1 million mainly due to adjustments required to correct deficiencies in accounts receivable reporting that were recognized in 2011. Additionally, 2012 Provision for Uncollectibles is lower due to lower sales, driven by exceptionally warm weather and low gas prices; as well as continued higher collection efforts.

7. Legal and Corporate Security increased by $1.0 million resulting from additional employees and external legal services to balance workload.

Witnesses: R. Lei
S. Qian

8. Operations increased by $7.9 million due to higher compliance related work such as above and below ground repairs. Furthermore, there were higher costs related to sewer lateral costs, hydrovac costs, incident and leak management safety initiatives, and path to zero safety initiative.

9. Information Technology is higher by $2.3 million due to higher CIS related hardware maintenance costs and other business application software maintenance.

10. Business Development and Customer Strategy decreased by $1.1 million mainly due to staff reductions and staff hiring delays, as a result of organizational restructure changes.

11. Human Resources increased by $3.5 million primarily attributed to severances, additional space leases, and higher facility maintenance costs.

12. Benefits are higher by $18.4 million primarily due to additional required pension contribution.

13. Pipeline Integrity and Engineering increased by $6.8 million as a result of higher integrity management, corrosion and leak survey costs, damage prevention costs and compliance and regulation initiatives to meet safety requirements.

14. Regulatory, Public and Government Affairs is higher by $1.1 million due to additional communication and other community outreach initiatives to reinforce the Company's core message around safety.

16. Corporate Cost Allocations increased by $5.0 million primarily resulting from higher compensation related costs. Please note the CAM is adjusted at Line 23 to reflect RCAM for utility reporting.

Witnesses: R. Lei
S. Qian

18. Capitalization (A&G) was higher by $8.0 million, driven by higher compensation related costs and pension costs.

20. Demand Side Management increased by $1.4 million as a result of higher level of Board Approved program spending.

Witnesses: R. Lei
S. Qian

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2012 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
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	2,353.1	58.67	5.89	3.456	138.6
2.	Short-Term Debt	113.7	2.84	1.31	0.037	1.5
3.		2,466.8	61.51		3.493	
4.	Preference Shares	100.0	2.49	2.40	0.060	2.4
						142.5
5.	Common Equity	1,443.8	36.00	8.52	3.067	
6.		4,010.6	100.00		6.620	
7.	Rate Base (Ex. B-2-1)	($Millions)			4,010.60	
8.	Utility Income (Ex. B-5-2)	($Millions)			280.70	
9.	Indicated Rate of Return				6.999	
10.	Sufficiency in Rate of Return				0.379	
11.	Net Sufficiency	($Millions)			15.20	
12.	Gross Sufficiency	($Millions)			20.70	
13.	Revenue at Existing Rates	($Millions)			2,349.40	
14.	Revenue Requirement	($Millions)			2,328.70	
15.	Gross Revenue Sufficiency	($Millions)			20.70	
	Common Equity					
16.	Allowed Rate of Return				8.520	
17.	Earnings on Common Equity				9.572	
18.	Sufficiency in Common Equity Return				1.052	

Witnesses: K. Culbert
R. Small

UTILITY INCOME
2012 HISTORICAL YEAR

Line No.		Col. 1 Utility Income ($Millions)
1.	Gas sales	2,001.0
2.	Transportation of gas	347.1
3.	Transmission, compression and storage revenue	1.3
4.	Other operating revenue	36.8
5.	Interest and property rental	-
6.	Other income	6.1
7.	Total operating revenue (Ex. B-3-1-pg.1)	2,392.3
8.	Gas costs	1,314.1
9.	Operation and maintenance	391.4
10.	Depreciation and amortization expense	292.9
11.	Fixed financing costs	2.0
12.	Debt redemption premium amortization	0.2
13.	Company share of IR agreement tax savings	25.3
14.	Municipal and other taxes	38.2
15.	Interest and financing amortization expense	-
16.	Other interest expense	-
17.	Cost of service (Ex. B-4-1-pg.1)	2,064.1
18.	Utility income before income taxes	328.2
19.	Income tax expense (Ex. B-4-1-pg.3)	47.5
20.	Utility income	280.7

Witnesses: K. Culbert
R. Small

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2012 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	2,380.0		140.1
2.	Unamortized Finance Costs	(26.9)		-
3.	(Profit)/Loss on Redemption	-		-
4.		2,353.1		140.1
5.	Calculated Cost Rate		5.89%	
	Short-Term Debt			
6.	Calculated Cost Rate		1.31%	
	Preference Shares			
7.	Preference Share Summary	100.0		2.4
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		2.4
11.	Calculated Cost Rate		2.40%	
	Common Equity			
12.	Board Approved Formula ROE		7.52%	
13.	100 Basis Point Allowance Before Earnings Sharing		1.00%	
14.	Total Allowed ROE for ESM Purposes		8.52%	

Witnesses: K. Culbert
R. Small

C – EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

DEFERRAL & VARIANCE ACCOUNTS
REQUESTED FOR CLEARANCE OCTOBER 1, 2013

1. EGD is requesting clearance of the deferral and variance accounts and balances shown at page 2 of this schedule, in conjunction with the January 1, 2014 QRAM proceeding and gas pricing changes. The Company is requesting this timeline due to a conflict with a required SAP maintenance process in September/October. The balances requested for clearance total approximately $(20.7) million, which is the combination of principal and interest amounts shown in columns 3 and 4.

2. As shown within the footnotes, or evidence referenced in the footnotes on page 2, EGD has provided some additional explanatory 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 April 1, 2013 prescribed interest rate for deferral and variance accounts. The eventual interest amounts to be cleared will be calculated using any updated Board prescribed quarterly interest rate that becomes 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 March 31, 2013		Forecast for clearance at January 1, 2014		
Line No.	Account Description	Account Acronym	Principal ($000's)	Interest ($000's)	Principal ($000's)	Interest ($000's)	
	Non Commodity Related Accounts						
1.	Demand Side Management V/A	2011 DSMVA	535.8	(46.8)	535.8	(40.5)	1
2.	Lost Revenue Adjustment Mechanism	2011 LRAM	-	-	(55.3)	(0.5)	1
3.	Shared Savings Mechanism V/A	2011 SSMVA	-	-	6,769.5	41.5	1
4.	Deferred Rebate Account	2012 DRA	(940.8)	(5.8)	(940.8)	(16.6)	
5.	Gas Distribution Access Rule Costs D/A	2011 GDARCDA	89.9	1.7	-	-	2
6.	Gas Distribution Access Rule Costs D/A	2012 GDARCDA	1,616.4	12.6	1,097.8	-	2
7.	Ontario Hearing Costs V/A	2012 OHCVA	(1,259.7)	(5.7)	(1,259.7)	(19.2)	3
8.	Unbundled Rate Implementation Cost D/A	2012 URICDA	155.0	1.5	155.0	3.3	
9.	Average Use True-Up V/A	2012 AUTUVA	4,361.3	16.0	4,361.3	63.7	4
10.	Tax Rate and Rule Change V/A	2012 TRRCVA	300.0	1.4	300.0	5.0	5
11.	Earnings Sharing Mechanism D/A	2012 ESMDA	(10,350.0)	(38.0)	(10,350.0)	(152.3)	6
12.	Electric Program Earnings Sharing D/A	2012 EPESDA	(281.7)	(1.0)	(281.7)	(3.7)	
13.	Ex-Franchise Third Party Billing Services D/A	2012 EFTPBSDA	(143.0)	(0.5)	(143.0)	(2.3)	
14.	Transition Impact of Accounting Change D/A	2013 TIACDA	88,716.0	-	4,435.8	-	7
15.	Total non commodity related accounts		82,799.2	(64.6)	4,624.7	(121.6)	
	Commodity Related Accounts						
16.	Transactional Services D/A	2012 TSDA	(26,077.3)	(208.0)	(26,077.3)	(495.1)	
17.	Unaccounted for Gas V/A	2012 UAFVA	2,067.9	7.6	2,067.9	30.1	
18.	Storage and Transportation D/A	2012 S&TDA	(699.8)	(7.4)	(699.8)	(15.5)	
19.	Total commodity related accounts		(24,709.2)	(207.8)	(24,709.2)	(480.5)	
20.	Total Deferral and Variance Accounts		58,090.0	(272.4)	(20,084.5)	(602.1)	

Notes:
1. The final 2011 DSMVA, SSMVA, and LRAM balances to be cleared will be those approved in the EB-2013-0075 proceeding, anticipated to be filed in Q2 2013.
2. The $1.1M forecast clearance amount, associated with the 2011 and 2012 GDARCDA balances, is the result of a revenue requirement calculation found in evidence at Ex.C-1-2.
3. The OHCVA calculation is found in evidence at Ex.C-1-5.
4. The AUTUVA explanation is found in evidence at Ex.C-1-3.
5. The TRRCVA explanation is found in evidence at Ex.C-1-4.
6. The ESMDA explanation is found in evidence at Ex.B-1-1 and B-1-2.
7. The TIACDA clearance is in accordance with the EB-2011-0354 Final Rate Order.

Witnesses: K. Culbert
R. Small

GAS DISTRIBUTION ACCESS RULE COSTS DEFERRAL ACCOUNT

1. Within the EB-2010-0146 and EB-2011-0277 Rate Orders, the Board approved a 2011 and 2012 Gas Distribution Access Rule Costs Deferral Account (“GDARCDA”) to record costs associated with the Company maintaining compliance with the Board’s Gas Distribution Access Rule directives.

2. As indicated within the GDARCDA evidence, Exhibit C, Tab 1, Schedule 2, at the time of the EB-2012-0055 proceeding, it was only possible to determine a 2012 partial GDARCDA revenue requirement. EGD did not know at that time, all of the related impacts in 2012 from previous GDAR requirements nor the full impact of the additional Board required GDAR amendments for Customer Service Rule (“CSR”) changes which were to be in effect in 2012. The result, as indicated in that evidence and as was approved by the Board, was that EGD was able to determine and clear a cumulative, but partial, 2012 GDARCDA revenue requirement in relation to GDAR required amounts incurred through 2011 for things other than the CSR related changes.

3. EGD is now able to determine the remaining 2012 impacts of the existing GDAR requirements and the additional CSR changes required by the GDAR amendment, and has included a remaining 2012 fiscal year revenue requirement impact in relation to these impacts for which the Company is seeking approval for clearance in 2013.

4. In the EB-2007-0615 Final Rate Order, and EB-2009-0055, EB-2010-0042, EB-2011-0008, and EB-2012-0055 Decisions the Board approved clearance of the 2007, 2008, 2009, 2010 and 2011 GDAR compliance costs incurred through 2011,

other than the CSR change related items, through revenue requirement calculations, which were included as part of one time rate rider adjustments to customers. The result is that the Company's distribution rates through 2012, did not contain the ongoing impact of GDAR compliance spending, and therefore, associated rate rider adjustments needed to be established and cleared annually. As a result, the total cumulative 2012 revenue requirement impact of the 2007, 2008, 2009, 2010, 2011 and 2012 Board Approved deferral account costs required 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 the remaining partial 2012 annual revenue requirement for CSR related items determined through a revenue requirement / cost of service type of calculation. This revenue requirement treatment is consistent with the EB-2007-0615, EB-2009-0055, EB-2010-0042, EB-2011-0008, and EB-2012-0055 Board Decisions.

5. EGD is not at this time able to estimate nor has it included the revenue requirement impacts of any Low Income Customer Service Rule changes which came into effect on January 1, 2013 through an amendment to GDAR which the Board adopted on September 6, 2012. The Company will bring forward the impact of these changes in a future proceeding.

6. Within this remaining partial revenue requirement calculation, the typical items included in a cost of service revenue requirement such as depreciation, total return on rate base including interest, equity and taxes, and other operating revenues and costs are being requested for recovery. The Company has used the 2007 Board Approved capital structure within the partial revenue requirement calculation, as it is the underlying capital structure within base rates and used in EGD's 2008-2012

Incentive Regulation approved rates mechanism. This is consistent with the previous 2007 through 2012 Approved GDARCDA revenue requirement determinations.

7. The Company is proposing to recover $1.1 million as part of the requested one time rate rider adjustment in October 2013, as shown within the proposed clearance balances within Exhibit C, Tab 1, Schedule 1, page 2, Columns 3 and 4.

8. The determination of the partial 2012 GDAR revenue requirement deferral account costs is shown in pages 4 through 8 of this schedule.

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY CAPITAL STRUCTURE
2012 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)	2012
7.	Ontario Utility Income	(683.1)
8.	Rate base	240.0
9.	Indicated rate of return	(284.63)%
10.	(Def.) / suff. in rate of return	(292.21)%
11.	Net (def.) / suff.	(701.3)
12.	Gross (def.) / suff.	(1,097.8)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY RATE BASE
2012 GDARCDA IMPACTS

($000's)

Line No.		2012
	Property, plant, and equipment	
1.	Cost or redetermined value	253.9
2.	Accumulated depreciation	(13.9)
3.		240.0
	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	240.0

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY INCOME
2012 GDARCDA IMPACTS

($000's)

Line No.		2012
	Revenue	
1.	Gas sales	(915.6)
2.	Transportation of gas	-
3.	Transmission and compression	-
4.	Other operating revenue	-
5.	Other income	-
6.	Total revenue	(915.6)
	Costs and expenses	
7.	Gas costs	-
8.	Operation and Maintenance	200.2
9.	Depreciation and amortization	47.6
10.	Municipal and other taxes	-
11.	Total costs and expenses	247.8
12.	Utility income before inc. taxes	(1,163.4)
	Income taxes	
13.	Excluding interest shield	(476.5)
14.	Tax shield on interest expense	(3.8)
15.	Total income taxes	(480.3)
16.	Ontario utility net income	(683.1)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2012 GDARCDA IMPACTS

($000's)

Line No.		2012
1.	Utility income before income taxes	(1,163.4)
	Add Backs	
2.	Depreciation and amortization	47.6
3.	Large corporation tax	-
4.	Other non-deductible items	-
5.	Any other add back(s)	-
6.	Total added back	47.6
7.	Sub total - pre-tax income plus add backs	(1,115.8)
	Deductions	
8.	Capital cost allowance - Federal	203.2
9.	Capital cost allowance - Provincial	203.2
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	203.2
17.	Total Deductions - Provincial	203.2
18.	Taxable income - Federal	(1,319.0)
19.	Taxable income - Provincial	(1,319.0)
20.	Income tax provision - Federal	(291.8)
21.	Income tax provision - Provincial	(184.7)
22.	Income tax provision - combined	(476.5)
23.	Part V1.1 tax	-
24.	Investment tax credit	-
25.	Total taxes excluding tax shield on interest expense	(476.5)
	Tax shield on interest expense	
26.	Rate base as adjusted	240.0
27.	Return component of debt	4.43%
28.	Interest expense	10.6
29.	Combined tax rate	36.120%
30.	Income tax credit	(3.8)
31.	Total income taxes	(480.3)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY REVENUE REQUIREMENT
2012 GDARCDA IMPACTS

($000's)

Line No.		2012
	Cost of capital	
1.	Rate base	240.0
2.	Required rate of return	7.58%
3.	Cost of capital	18.2
	Cost of service	
4.	Gas costs	-
5.	Operation and Maintenance	200.2
6.	Depreciation and amortization	47.6
7.	Municipal and other taxes	-
8.	Cost of service	247.8
	Misc. & Non-Op. Rev	
9.	Other operating revenue	-
10.	Other income	-
11.	Misc, & Non-operating Rev.	-
	Income taxes on earnings	
12.	Excluding tax shield	(476.5)
13.	Tax shield provided by interest expense	(3.8)
14.	Income taxes on earnings	(480.3)
	Taxes on (def) / suff.	
15.	Gross (def.) / suff.	(1,097.8)
16.	Net (def.) / suff.	(701.3)
17.	Taxes on (def.) / suff.	396.5
18.	Revenue requirement	182.2
	Revenue at existing Rates	
19.	Gas sales	(915.6)
20.	Transportation service	0.0
21.	Transmission, compression and storage	0.0
22.	Rounding adjustment	0.0
23.	Revenue at existing rates	(915.6)
24.	Gross revenue (def.) / suff.	(1,097.8)

Witnesses: K. Culbert
R. Small

2012 AVERAGE USE TRUE-UP VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2012 Average Use True-up Variance Account ("AUTUVA") amount.

2. Table 1 of Appendix A details the calculations that result in the amount of $4.36 million that will be debited (collected) from rate payers. The recovery is primarily attributable to a shortfall in Rate 6 average use, partially offset by favourable residential average use.

3. The shortfall in Rate 6 average use can primarily be attributable to the slower economic recovery than expected. The volumetric forecast of average use in the 2012 budget incorporated expectations on a strong rebound from the 2008-2009 recession but actual consumption did not meet this optimistic view as it was lower than in the budget. Rate 6 customers include apartment, commercial, and industrial customers and their consumption patterns are heavily impacted by economic conditions and production levels that are often difficult to predict.

4. 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, 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.

Witnesses: C. Ho
S. Riccio

The calculation of the volume variance between forecast average use and actual normalized average use excludes the volumetric impact of Demand Side Management programs in that year. The revenue impact is 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.

5. As was the case in previous proceedings, the audited actual volume savings of DSM activities will not be available until later in the 2013 year. Therefore, 2012 Board Approved Budget DSM volumes still represent a reasonable estimate of 2012 actual.

6. Tables 2 and 3 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 to 4.

Witnesses: C. Ho
S. Riccio

TABLE 1

2012 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

Exhibit Reference:	EB-2011-0277, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 15	Tables 1-2 on pages 4-5		EB-2011-0277, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 1		EB-2011-0277, Exhibit B, Tab 1, Schedule 5, Tables 3-4				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	2012 Budget Annual Use (m^3)	2012 Normalized Actual Annual Use (m^3)	Normalized Usage Variance (m^3)	Budget Customer Meters	Normalized Volumetric Variance (10^6m^3)	2012 DSM Budget (10^6m^3)	2012 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	2,510	2,529	18	1,826,796	33.4	(10.0)	(10.0)	0.0	33.4	0.0525	1.75
6	30,122	28,941	(1,182)	157,500	(186.1)	(26.3)	(26.3)	0.0	(186.1)	0.0328	(6.11)
Total					(152.7)	(36.3)	(36.3)	0.0	(152.7)		(4.36)

Witnesses: C. Ho
S. Riccio

TABLE 2
GENERAL SERVICE RATE 1
2012 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 ($10^6 m^3$)	807.0	780.4	681.9	481.8	279.0	132.1	97.5	102.5	109.5	196.6	369.5	605.0	4,642.9	Exhibit B, Tab 3, Schedule 2
1.2	Customer Meters	1,826,998	1,829,526	1,832,013	1,833,420	1,833,337	1,831,393	1,830,977	1,830,088	1,834,396	1,845,680	1,851,488	1,855,883	1,836,267	Exhibit B, Tab 3, Schedule 4, Col. 1 Item 1.1
1.3	Average Use per Customer (m^3)	442	427	372	263	152	72	53	56	60	107	200	326	2,529	

Witnesses: I. Chan

Witnesses: C. Ho
S. Riccio

TABLE 3
GENERAL SERVICE RATE 6
2012 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 ($10^6 m^3$)	750.1	758.2	705.2	477.7	311.5	129.4	93.1	98.9	119.3	199.1	372.9	600.3	4,615.5	Exhibit B, Tab 3, Schedule 2
1.2	Customer Meters	160,152	160,582	160,467	160,035	158,614	157,175	155,735	154,544	154,960	157,012	158,939	160,177	158,199	Exhibit B, Tab 3, Schedule 4, Col. 1 Item 1.2
1.3	Average Use per Customer (m^3)	4,683	4,722	4,394	2,985	1,964	823	598	640	770	1,268	2,346	3,748	28,941	

Witnesses: I. Chan

Witnesses: C. Ho
S. Riccio

Tax Rate and Rule Change Variance Account

1. Within the 2012, EB-2011-0277 Interim Rate Order, the Board approved a 2012 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 2012 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 EB-2011-0008 proceeding, the Company provided, and the Board approved, updated tax savings calculations for the years 2010 through 2012. Evidence in EB-2011-0008 (Exhibit C, Tab 1, Schedule 4, page 3, Column 5, Line 62), showed an updated cumulative savings amount of $25.64 million for 2012. Within that schedule, at Column 5, Line 66, the incremental 2012 amount to be credited through rates, of $4.58 million, was identified. In the 2012 Approved Total Revenue Determination, shown in the EB-2011-0277 Interim Rate Order, Appendix A, Schedule 1, Row 9, the $4.58M is credited to rate payers. A copy of the then updated summary of forecast tax savings and sharing amounts, approved in EB-2011-0008, is reproduced at page 4 of this exhibit.

3. As a result of Ontario budget Bill 114, which froze Ontario’s general corporate tax rate at 11.5%, thereby eliminating anticipated provincial corporate income tax rate reductions in 2012 and beyond, the EB-2011-0008 approved tax savings and sharing agreement requires a further update. Prior to Bill 114, the Company and approved tax savings amounts anticipated an effective provincial income tax rate of

11.25%. The effective rate was based on the assumption that Ontario's general corporate tax rate would drop from 11.5% to 11.0%, on July 1, 2012, or halfway through the fiscal year. Bill 114 froze Ontario's general corporate tax rate at 11.5%, thereby creating a 0.25% rate variance in 2012, which was captured in the tax sharing amounts approved in EB-2011-0008 and passed on to ratepayers in EB-2011-0277.

4. The updated 2012 cumulative annual shared tax savings amount of $25.34 million, which incorporates the effects of Bill 114, or an Ontario general corporate tax rate of 11.5%, is shown at Line 62, Column 5, page 3, of this exhibit. The previously approved EB-2011-0008 annual tax savings and sharing amounts are shown at Line 63, on page 3, and at Line 62 on page 4.

5. The impact for 2012 is that the previously approved cumulative annual credit incorporated into rates of $25.64 million, was overstated by $0.3 million, as compared to the updated 2012 cumulative annual credit of $25.34 million, which is shown on Line 64, page 3, of this exhibit. To account for this variance, the Company has recorded a $0.3 million increase/credit to revenues, and a corresponding debit to the 2012 TRRCVA. The Company is requesting clearance of the 2012 TRRCVA amount, along with the other deferral and variance account balances shown in Exhibit C, Tab 1, Schedule 1, page 2.

Witnesses: K. Culbert
R. Small

Table 1

Updated Summary - Sharing of Tax Change Forecast Amounts

(EB-2011-0008 Approved Sharing amounts updated for changes in Provincial Income Tax Rates)

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%	26.50%	
24.	Tax Impact	2.44	4.23	4.91	4.89	5.48	
25.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.65	6.31	7.12	6.81	7.45	31.35
26.	Incremental Amount	3.65	2.66	0.81	(0.31)	0.65	
27.	**50% of the Amount to Reduce Rates**	**$1.83**	**$1.33**	**$0.40**	**-$0.16**	**$0.32**	
	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%	26.50%	
34.	Tax Rate Variance	2.62%	3.12%	5.12%	7.87%	9.62%	
35.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	11.90	18.29	22.36	
36.	Grossed-up Tax Savings	9.16	10.82	17.25	25.49	30.42	93.14
37.	Incremental Amount	9.16	1.66	6.43	8.24	4.93	
38.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$3.22**	**$4.12**	**$2.46**	
	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%	26.50%	
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**	**50.71**	159.93
61.	**Total Incremental Ratepayer Amounts into rates (lines 27+38+47+54+59)**	**$7.44**	**$1.43**	**$7.14**	**$6.25**	**$3.08**	
62.	**Updated of Annual Ratepayer & Company Shareholder Tax Savings (50% of row 60)**	**$7.44**	**$8.87**	**$16.01**	**$22.26**	**$25.34**	$79.92
63.	**2011, EB-2010-0146 Approved / Updated Agreement Annual Ratepayer Tax Savings**	***$7.44***	***$8.87***	***$16.01***	***$22.26***	***$25.64***	*$80.22*
64.	2012 TRRCVA debit from unrealized Provincial Income tax rate change ($25.34M - $25.64M) (col.5, line 62 - 63)					0.30	

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.	($ Millions)	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						
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 Resulting 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)			

Witnesses: K. Culbert
R. Small

2012
ENBRIDGE GAS DISTRIBUTION
ONTARIO HEARING COSTS
VARIANCE ACCOUNT

Line No.	Test Year Proceeding Costs	Col. 1 Baseline Regulatory Cost Budget ($000's)	Col. 2 2012 Regulatory Costs Incurred ($000's)	Col. 3 Variance ($000's)
1.	Legal	840.0	378.6	
2.	Intervenor	1,155.0	161.9	
3.	Ontario Energy Board	4,040.0	2,989.5	
4.	Consultants	500.0	35.4	
5.	Transcripts, newspaper notices, printing, other	420.0	462.0	
6.	Sub-total	6,955.0	4,027.4	
7.	Other proceedings	1,887.5	555.4	
8.	2009 Agreed to OHCVA threshold reduction	(3,000.0)	-	
9.	Actual versus OHCVA threshold variance	5,842.5	4,582.8	(1,259.7)

Line No.	Breakdown of Other Proceedings (Line 7, Col. 2 above)	
10.	Renewable Natural Gas / Biogas	414.2
11.	DSM	113.2
12.	CIS/Customer Care Consultative	18.1
13.	Consultation on Energy Issues / Low Income Consumers	9.9
14.	Total - Other proceedings	555.4

Witnesses: K. Culbert
R. Small

BACKGROUND AND EXPLANATION OF TRANSACTIONAL SERVICES REVENUE

1. The purpose of this evidence is first to provide an overview of transactional services ("TS") revenue by explaining on what basis transactional services revenue is generated and the types of transactional service transactions. Following this an analysis of the transactional services revenue and/or gas cost reductions generated by various types of transactions available to Enbridge Gas Distribution Inc. ("EGD") to optimize gas supply for ratepayers is presented. The evidence also considers why compensating the utility through a revenue sharing mechanism is beneficial for ratepayers.

Gas Supply Plan

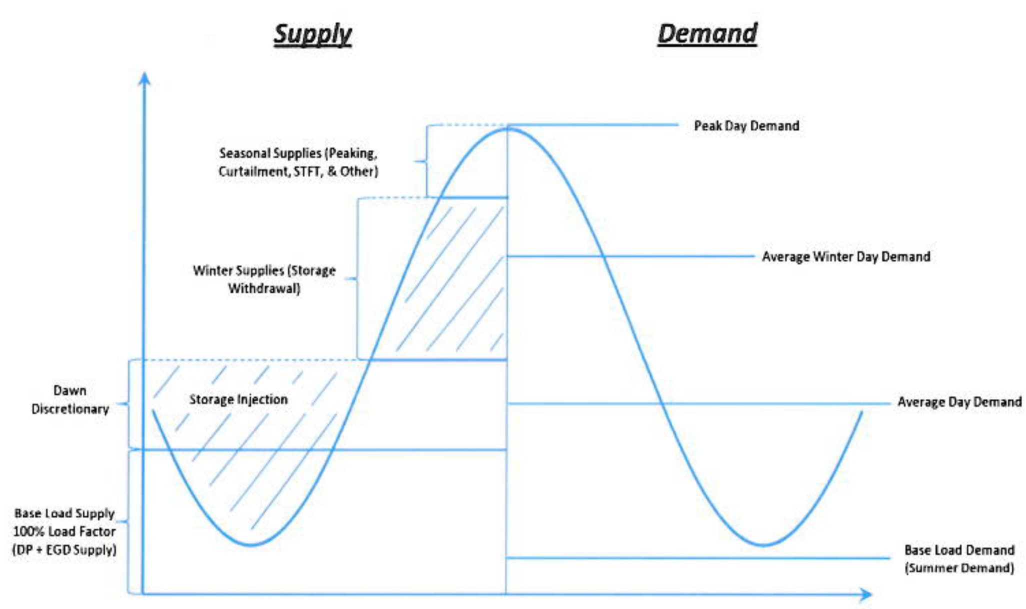
2. EGD procures natural gas supply, transportation and storage in order to ensure that it is able to meet franchise demand 24 hours a day, 7 days a week, and 365 days a year. In developing its gas supply plan EGD balances reliability of supply and transportation, diversity of production source and pipelines and a need for a level of flexibility to respond to variation in demand against cost to arrive at a robust and manageable plan suited to meet the needs of its customers.

3. Demand on the EGD distribution system can be broken out into several components: base load demand, average day demand, seasonal or average winter demand and peak day demand. Base load demand refers to load which is not temperature sensitive and is defined as demand during the summer (July & August). Winter demand is comprised of base load demand plus heating load. Peak day demand refers to load conditions which are the greatest on a day within a year. Average day is comprised of all aforementioned three demand components and is calculated as annual demand divided by 365 days.

Witnesses: J. LeBlanc
D. Small
M. Giridhar

4. EGD serves these demands through various components of its supply portfolio including: base load supply, discretionary supply, winter supplies and seasonal supplies. Base load supply is comprised of long haul contracts on TransCanada Pipelines Limited ("TCPL") and Alliance/Vector pipelines along with Direct Purchase ("DP") deliveries. Discretionary supply includes purchases at the Dawn trading hub ("Dawn"). Base load and discretionary supplies are used to serve average day demand and provide gas for injection into storage when not required by the market. Aforementioned sources of supply plus paths of shorter haul on Union and TCPL pipelines are utilized to meet winter demand along with withdrawals from storage. When demand increases to a level at or approaching peak day demand additional seasonal supplies including peaking supplies and curtailment are employed. The figure below provides a stylized picture of supply and demand.

Figure 1. – Relationship of EGD's Gas Supply and Demand



Witnesses: J. LeBlanc
D. Small
M. Giridhar

5. Every year there are a number of considerations that go into the development of the supply portfolio

    i. changes in degree days, customer adds, change in average use
    ii. customer migration between Sales and Direct Purchase service
    iii. changes in peak day demand requirements – not only changes to the absolute level of peak day but how it relates to average winter daily demand
    iv. changes in the market place – access to new supply alternatives, new pipeline transportation opportunities and alternative storage arrangements
    v. review of how the market responded the previous year to firm versus interruptible transportation
    vi. other changes in supply reliability, diversity and operational flexibility

6. EGD's Gas Supply Strategy group uses an application known as SENDOUT to assist in the development of the supply portfolio. Firm transportation contracts (i.e., Firm transportation service on TCPL and Alliance/Vector pipelines) are a sunk cost meaning that they must be paid for regardless of whether they are used to transport gas or not. SENDOUT uses the attributes of the various supply and demand components to maximize the use of firm transportation contracts. It then helps determine how to best use other supply options including storage levels to ensure demand is met.

7. Transactional services optimization is not considered by the planning group or modeled by SENDOUT at the planning stage as it is not possible to predict when transportation will be surplus on the day (due to fluctuations in demand) or the daily pricing that will drive the value of optimization deals. However, as can be

seen in the above graphical representation of how demand is met with a SENDOUT optimized supply plan, it is important to note that base load transportation exceeds base load demand (also known as average summer daily demand) and the combination of all transportation components exceeds the average winter day demand. It is therefore expected at a general level that there will be surplus transportation capacity that can be made available for optimization on certain days throughout the year. This is considered in the annual ratemaking process. For 2012 an amount of $8 million was incorporated into rates to reflect the ratepayer's share of the generation of transactional services revenue in some form.

8. The table below identifies the peak day design forecast for 2012 and the contracts that were required to meet that peak day demand as per the gas supply plan.

Witnesses: J. LeBlanc
D. Small
M. Giridhar

Table 1 - 2012 Peak Day Design Forecast Fulfillment Summary

As per the 2012 Budget

In Gigajoules (GJs)	CDA	EDA	Total
Demand	3,164,452	577,411	3,741,863
Less Curtailment	(129,737)	(31,788)	(161,524)
	3,034,716	545,623	3,580,339
TCPL FT Capacity	90,424	196,970	287,394
TCPL STFT	250,000	75,000	325,000
TCPL Short Haul	139,879	114,000	253,879
TCPL STS	369,464	80,611	450,076
Direct Purchase (Ontario T-Service)	349,653	32,693	382,346
Storage and Delivered Services	1,741,278	-	1,741,278
Peaking Service	94,018	46,349	140,367
	3,034,716	545,623	3,580,339

Roles of various departmental groups in the development and execution of the EGD gas supply plan

9. Gas Supply Strategy group – The primary responsibility of the Gas Supply Strategy group is to identify the necessary assets – storage, transportation, peaking services and delivered services – required in the supply plan to meet the peak, seasonal and annual demands of EGD's customers under design day conditions.

Witnesses: J. LeBlanc
D. Small
M. Giridhar

10. Gas Supply group – The primary responsibility of this group is to arrange for the necessary gas supplies required to meet franchise demand and fill storage. The group also ensures that the long haul transportation contracts are operated at 100% load factor and that peaking and delivered services are procured as necessary. Also, once authorized by the Gas Control group, this group enters into transactional service deals – both storage optimization and transportation optimization – with third party marketers.

11. Gas Control group – Throughout the year the Gas Control group is responsible for forecasting the day to day demand of EGD's customers. The Gas Control group then nominates (or schedules) on a daily basis for the delivery of natural gas under the various pipeline and storage contracts that EGD has entered into. The Gas Control group also has the responsibility of determining whether or not to call for curtailment during the winter season. Once satisfied that the demands of EGD's customers will be met, the Gas Control group authorizes the Gas Supply group to use any remaining temporarily surplus transportation and/or storage assets to generate transactional service revenue.

12. Gas Cost Accounting group - Upon the receipt of the various commodity, transportation and storage invoices the Gas Cost Accounting group reconciles and verifies these invoices to ensure accurate and timely payments to third parties. The Gas Cost Accounting group also ensures that these amounts are booked accurately as either a gas cost or transactional services revenue item and that amounts are booked correctly to either the Purchase Gas Variance Account ("PGVA") or the Transactional Services Deferral Account ("TSDA").

Witnesses: J. LeBlanc
D. Small
M. Giridhar

13. Organizing the department in the above described groups helps ensure that decisions get made for the right reasons. Everything starts with the Gas Supply Strategy group which develops a gas supply plan aimed at reliably and cost effectively meeting customer demand. Once the plan is in place, the Gas Control group carries out and monitors implementation of the plan. They decide if and when capacity is available for the Gas Supply group to optimize and generate Transactional Services revenue. The Gas Cost Accounting group summarizes and properly records the transactions throughout the year.

Transactional Services

14. The concept of transactional services was first introduced in the mid 1990's under the premise that if circumstances arose where the assets acquired by EGD to meet customer demand were not fully required then those assets could be made available to generate third party revenue. To be considered transactional services the transaction opportunities must be unplanned, a third party must be requesting a service and EGD must have temporarily surplus capacity. To help better understand these elements they are explored in more detail below.

15. Unplanned – Optimization transactions opportunities cannot be forecast at the time the gas supply plan is developed and are therefore unplanned. There are two circumstances that must be known in order for optimization transactions to be forecast and planned. First the knowledge that a specific level of transportation capacity will be surplus at specific points in time and, second, the value that EGD can extract for that specifically identifiable surplus capacity must be known. These circumstances cannot be known at the gas supply plan development stage.

Witnesses: J. LeBlanc
D. Small
M. Giridhar

16. Third party service request – As noted above EGD does not sell natural gas to third parties except in unusual operational conditions (pipeline or storage force majeure and extreme weather events). In its Reasons for Decision in RP-2003-0203 dated November 1, 2004 the Board disallowed the practice of bundling commodity sales with surplus transportation capacity to generate transactional service revenues. As a result EGD is unable to market surplus capacity to end use customers other than its own, as end use customers typically require units of energy at a particular location and time rather than units of capacity. Consequently, a request from a third party marketer or supplier who is able to combine surplus EGD capacity with commodity sales is needed for generating transactional services revenue.

17. Temporarily surplus capacity - EGD has surplus transportation capacity to the franchise at various points in time because it procures transportation at a level to meet peak day demand in the franchise. Temporarily surplus capacity, as one of the elements of transactional services, does not include surplus commodity as EGD rarely if ever has surplus commodity purchases. Gas is purchased either to serve the customer on the day or to inject into storage for use to serve demand at a later date.

18. Transactional services optimization can be grouped into two different categories – storage optimization and transportation optimization. Storage optimization transactions typically rely on storage or loan of gas between two points in time but at the same location (i.e., Dawn). The transaction is made possible because of the existence of a price spread that exceeds the cost of storing or loaning gas for the period of time in question. Transportation optimization transactions typically rely on the exchange of gas on the day between two locations. The transaction is

made possible because the price spread between the two locations exceeds the cost of completing the exchange between the two locations.

19. An example of storage optimization is as follows: A third party has supply at its disposal in April but does not have a market for that supply until August. The third party therefore approaches EGD about the possibility of storing gas until August. If EGD can accommodate such a request – an injection in April with a withdrawal in August - then EGD will do so. The fee for this service will be based upon the price differentials between April and August which generates net revenue.

20. An example of transportation optimization occurs when a third party has gas available at a particular point (Dawn), and needs the gas at another point (Iroquois), but does not have a way of getting the gas there. EGD is approached by the third party and, without impacting its ability to meet customer demand, can accommodate a point to point exchange of gas through the use of one of its transportation contracts. The price spread between the two points generates net revenue and the two parties proceed with the deal.

21. Since the assets used to enter into these optimization transactions are being paid for by the customer, through EGD's rates, the majority of the revenue generated should and does flow back to the customer base. To incent EGD to work to maximize the revenue generated, and therefore maximize the benefit to customers in the form of reduced rates, a sharing mechanism has and continues to exist where a portion of optimization revenues generated is returned to EGD for the benefit of shareholders.

Types of Transactional Services Exchanges

22. While there may be opportunities during the winter months to enter into transactional services deals the majority of deals occur in the summer months. During the summer months, when demand is less than the amount of gas that can be moved on base load supply contracts, EGD will continue to buy gas to fill that transportation capacity to fill storage as discussed earlier. The transportation associated with this gas, which is surplus to meeting customer demand on the day, creates one of the primary opportunities to generate transactional services exchanges.

23. Unlike the CDA where more transportation options exist, EGD is dependent on TCPL pipeline capacity to meet the peak and winter demand in the Eastern Delivery Area (EDA). It is therefore necessary to contract for a significant level of long haul transportation to the EDA resulting in long haul transportation that significantly exceeds the average summer daily demand in the EDA. The gas supply plan therefore intends for this excess supply to be diverted to storage for use in the following winter. This need for significant diversion to storage provides opportunity for transactional services. The size of the diversions over a period of time can allow for capacity release exchanges (described in detail later on), with their enhanced value, to be done rather than base exchanges on the day if the right conditions exist going into the storage injection season. For this reason many examples given below focus on EDA related transportation. The following table provides a comparison of the assets required to meet peak day, average winter and average summer daily demands in the EDA in support of examples discussed later.

Table 2 - Eastern Delivery Area Demand Summary

Eastern Delivery Area (EDA)
As per 2012 Budget

In Gigajoules (GJs)	Peak Day	Avg Winter Demand (January to March)		Avg Summer Demand (April to October)	
Demand	577,411	334,742		102,594	
Less Curtailment	(31,788)	-		-	
	545,623	334,742	(A)	102,594	(C)
TCPL FT Capacity	196,970	196,970		196,970	
TCPL STFT	75,000	75,000		-	
Direct Purchase (Ontario T-Service)	32,693	32,693		32,693	
Sub Total	304,663	304,663		229,663	
TCPL Short Haul	114,000				
TCPL STS	80,611				
Peaking Service	46,349	-		-	
	545,623	304,663	(B)	229,663	(D)
Amount Required from TCPL Short Haul and TCPL STS		30,079	(A-B)		
Amount of Long Haul required to be diverted to storage				127,069	(D-C)

24. The following is a description of the types of exchange deals that EGD has done in the last few years, including the year that is the subject of this application. A copy of a TransCanada system map has been included as an aid as certain delivery

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points on their system, such as Emerson and Iroquois, and their relative position on TCPL's system are referenced in the examples (See Appendix A).

25. Base exchange – A base exchange is the simplest type of exchange. EGD gives a third party gas at one location and receives gas back from that third party at a different location on the same day. The Iroquois/Dawn exchange described earlier is an example of a typical base exchange. If for illustration the proposed exchange volume was 50,000 GJs and it was a day in July where (equivalent to the average summer day in Table 2 above) the customer demand on the day was 102,594 GJs /u
EGD would be able to complete the deal as 50,000 GJs is less than the 127,069 GJs being diverted to storage using long haul contract capacity. From a /u
gas supply plan perspective nothing has changed. 127,069 GJs gets injected into /u
storage but by doing the deal transactional services revenue is generated for the benefit of ratepayers. Base exchanges meet the elements of transactional services as they are unplanned, a third party is requesting service and EGD has adequate temporary surplus capacity.

26. STS-RAM credits exchange – To understand STS-RAM credit exchanges, STS-RAM credits themselves and how they are accumulated and consumed must first be understood. STS-RAM[1] credits are a characteristic of TCPL's Storage & Transportation Service (STS) contract service, are made available from November 15th to April 15th and arise when EGD does not fully utilize 100% of its daily contracted TCPL STS capacity. Credits can accumulate throughout the month, are only available for use within that month and can only be applied against TCPL

[1] As an aside it should be noted that the recent NEB decision, RH-003-2011, eliminates STS-RAM credits and FT-RAM credits so these transactional services opportunities will end in 2013.

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Interruptible Transportation (IT) costs. This is a unique feature that impacts the definition of temporarily surplus. Transportation contracts can be deemed temporarily surplus if they are not required to meet customer demand on a particular day. RAM Credits can be deemed temporarily surplus at a point in time in the month when EGD determines that the accumulated credits will not be used up to meet the demand of utility customers in the month.

27. STS contracts are used in the winter to withdraw gas from storage to supplement contracted TCPL long haul capacity to meet customer demand. As Table 2 above showing the situation in the EDA indicates through a comparison of peak day demand to average winter day demand, there will be days throughout the winter when EGD will not require 100 % of its STS capacity. If credits accumulate on certain days, and during the month EGD requires IT services to meet the daily customer demand, the associated costs of the IT services will be offset in part by the accumulated STS-RAM credits. This is what has been referred to in past hearings as "STS-RAM for own use"[2] and these credits are treated as gas cost reductions and therefore get booked to the Purchased Gas Variance Account (PGVA). If as the end of the month approaches the Gas Control group determines that it will not require IT services to meet customer demand and that it has excess STS-RAM credits on hand that will expire, it will authorize the Gas Supply group to proceed to try and extract value from those expiring credits. The Gas Supply group will then work with third parties interested in an exchange where STS-RAM credit value can be realized through use of the credits as an offset to TCPL IT used to deliver gas to the third party in the exchange. As an example, a third party may be interested in moving gas from Empress to Emerson however, the only way they

[2] "STS-RAM credits for own use" do not meet the elements of transactional services as no third party is involved in realizing their value.

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can do that is by using TCPL IT and paying the applicable toll. If EGD were to instead take possession of the gas at Empress and move it on TCPL IT, then EGD will be able to use STS-RAM credits to reduce the effective cost of the transportation. EGD would then give the gas back to the third party at Emerson and EGD and the third party would agree on a price that allows for a sharing of the benefit from the use of the STS-RAM credits thus creating transactional services revenue. STS-RAM exchanges meet the elements of transactional services as they are unplanned, a third party is requesting service and EGD has adequate temporary surplus capacity.

28. Capacity release exchange – As Table 1 above illustrates, EGD requires 100% of its contracted TCPL long haul capacity to meet peak day demand. In the summer, as discussed previously, EGD continues to operate its long haul contracts at 100% load factor and injects the amount in excess of customer demand on the day into storage for use in the following winter. Utilizing these contracts at 100% load factor means a characteristic of these contracts known as FT-RAM credits are not available to EGD. Above a simple exchange, known as a base exchange, has already been described. An alternative to a base exchange like the Iroquois/Dawn exchange example used earlier, would be for EGD to give gas to a third party at Empress (instead of Iroquois) and still receive the gas back from the third party at Dawn. The only added nuance would be that, instead of using its TCPL long haul contract to deliver the gas at Iroquois, EGD would temporarily assign the associated long haul capacity to the third party. From EGD's perspective, nothing is different from the earlier base exchange example. EGD exchanged its gas and its transportation capacity for equivalent gas delivered at Dawn for injection into storage. Additional value however may be created from the point of view of the third party as it can choose to resell the gas it received from EGD at Empress at a

relatively close point like Emerson using TCPL IT for delivery which, as it has left the assigned TCPL Firm Transportation ("FT") empty, triggers the availability of the FT-RAM credits. The value of the FT-RAM credits offset by the TCPL IT cost provides a net benefit to the third party that can be applied against the price differential between the gas they sold at Emerson and the cost of the gas they would have to purchase at Dawn in order to complete the exchange. As part of the exchange the third party and EGD would agree on pricing that allows for a sharing of that additional value generated by the counterparty having access to the FT-RAM credits.

29. As an alternative to capacity release exchanges EGD could have deviated from the recommendations of its SENDOUT model, to utilize long haul contracts at 100% load factor, and leave a portion of its FT capacity empty thereby generating FT-RAM credits for "own use". This alternative was discussed as part of an undertaking Response (J1.1) in the EB-2012-0055 proceeding. The analysis presented later on in this evidence shows that this alternative generates significantly less value for ratepayers. This is true even if EGD receives a share of the value generated from the capacity release exchanges through the transactional services revenue sharing mechanism.

30. Unlike a base exchange that is done on the day, the value to a third party of a capacity release exchange type of transaction is further enhanced, due to the fact it is locked in for a period of time (potentially several months) offering predictability. From EGD's perspective, leaving transactional service opportunities in the summer until the gas day may limit the size and value of the exchange deals available whereas entering into a deal for the entire summer ensures greater value. Capacity release exchanges meet the elements of transactional services as they

are unplanned, a third party is requesting service and EGD has adequate temporary surplus capacity.

31. What can sometimes be difficult to understand in the case of capacity release exchanges is the notion that they cannot be planned (and are therefore unplanned according to the earlier described elements of transactional services) in advance as part of the gas supply plan due to the fact that it is known that there will be surplus capacity throughout a large portion of the summer and EGD will be injecting gas into storage. First of all, as described earlier in the definition of "unplanned", there are two circumstances that must be in place to be planned. One is that pricing, and therefore whether or not there is value sufficient to warrant completing a deal, must be known. At the gas supply planning stage in late spring, pricing is not known as there are too many variables in the market to be able to find a third party willing to price and complete a transaction. Secondly, one must know what specific level of transportation capacity will be available for a specific point or period of time. This second circumstance is complicated by STS withdrawal rights associated with EGD's STS contracts. To explain this important nuance one must understand STS withdrawal rights (another characteristic of TCPL STS contracts) and how they arise.

32. STS withdrawal rights are accumulated when gas is diverted and injected into storage using EGD's STS contract capacity. They do not accumulate if gas is injected into storage using a capacity release exchange to Dawn as STS contract capacity is not used to inject the gas in this situation. EGD begins the winter with the necessary STS withdrawal rights accumulated as dictated by the gas supply plan. As winter unfolds, and variations in demand as compared to the gas supply plan occur, more or less gas than expected is withdrawn from storage and

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transported using STS withdrawal rights. This variability affects how many STS withdrawal rights EGD will have left on hand to roll into its next season requirement and will therefore influence how many STS withdrawal rights that will need to be generated in the upcoming storage injection season. The level of STS withdrawal rights[3], as compared to plan, affects whether the Gas Control group can authorize capacity release exchanges and at what volume level.

33. In the EB-2012-0055 Decision rendered by the Board, capacity release exchanges were determined to not be transactional services and EGD was therefore directed to treat capacity release exchange revenues as a pass-through, in their entirety, to ratepayers rather than use the sharing formula applicable to transactional services revenue. The Board agreed with EGD that capacity release activities were not undertaken on a planned basis and were therefore unplanned (one of the elements of transactional services). The Board did not mention whether it considered the fact that a third party is needed to fulfill the elements of transactional services however EGD is of the view that it is one of the three elements needed. The point of departure between this evidence and the EB-2012-0055 Decision is with regard to the third element of transactional services, temporarily surplus capacity. The Board stated "The Board notes that in a capacity release, the gas purchased by Enbridge at Empress is required to serve its customers." In fact, the transportation used to complete capacity release exchange transactions is temporarily surplus capacity as it is not required to meet the demand of its customers on the day. The transportation used to complete capacity release exchange transactions is

[3] Due to the warmer than expected winter in 2012 EGD recognized that it would come out of the heating season with an unusually large number of STS Withdrawal Rights remaining. This partly explains the level of transactional services Capacity Release Exchanges in 2012.

temporarily surplus capacity in the same way that it is temporarily surplus capacity for base exchanges and for STS-RAM credit exchanges.

<u>Summary of transactional services for 2012 and their proposed disposition</u>

34. Appendix B provides a summary of the transactional services revenue generated in 2012.

35. Appendix C provides details of the monthly capacity release volumes in 2012 and the associated revenues.

<u>Why EGD should be incented to maximize capacity release exchanges through treatment as transactional services</u>

36. During the summer the average demand is less than the contracted long haul FT capacity to the EDA (see Table 2 above). EGD continues to flow that capacity at 100% load factor and make that excess gas available for injection into storage. There are four options available to EGD to get the excess gas into storage. The first would be to simply divert the gas from the EDA using its STS capacity contracts to inject the gas into storage. This option would involve no transactional service transaction and would not create any financial benefit to the ratepayer or the shareholder. The second option is to enter into a base exchange deal with a third party on a day or a number of days throughout the summer which still provides EGD with gas for injection as per the supply plan but in this case there will be avoided fuel cost as well as revenues generated from the exchange. The downside to such a transaction will be that by waiting until the gas day to enter into an exchange may limit the size of the volume to be exchanged and consequently its value. The limit to the size of the transaction will be dependent upon whether or not there is a market for these types of deals on the day. The third option available

would be to enter into a capacity release exchange deal. EGD still receives gas for injection into storage, as is required by its gas supply plan. The advantage to this option is that locking in a fixed volume for the entire summer with the third party provides greater value thereby increasing the amount of transactional services revenue generated. The fourth option would be for EGD to purposely leave a portion of its long haul FT capacity empty in order to generate FT-RAM credits and the resulting value. The only way to collect the FT-RAM credits would be to flow gas on TCPL IT. Under this option there would be transportation savings that would allow EGD to acquire additional gas at Empress and avoid buying an equivalent volume at Dawn thereby generating gas costs saving that would flow to the PGVA.

37. It is difficult to quantify how much transactional services revenue may have been generated during the summer of 2012 if EGD had followed the second option- base exchanges - for the entire volume that was being diverted back to storage. What is known is that during the summer EGD was able to do base exchanges for an average fee of $0.15 /GJ. Hypothetically if EGD had done base exchanges for the entire volume associated with capacity release exchanges it may have generated $3.8 million (translating into $2.9 million in benefit to ratepayers) in transactional services revenue. By comparison transacting under the third option – a capacity release exchange - EGD was able to generate $18.6 million in revenue. This translated into a $14.0 million benefit to the ratepayers if treated as transactional services revenue as EGD believes it should be. If option 4 had been used and EGD had intentionally left a portion of its long haul capacity empty to generate FT-RAM credits, procured additional supplies and moved those supplies via TCPL IT service, the most that could have been saved would have been $1.9 million in gas costs. The following table summarizes the above analysis.

Witnesses: J. LeBlanc
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Table 4 - Summary of options available to maximize transportation value while still injecting gas into storage according to the gas supply plan (see Appendix D for more detail on the calculations)

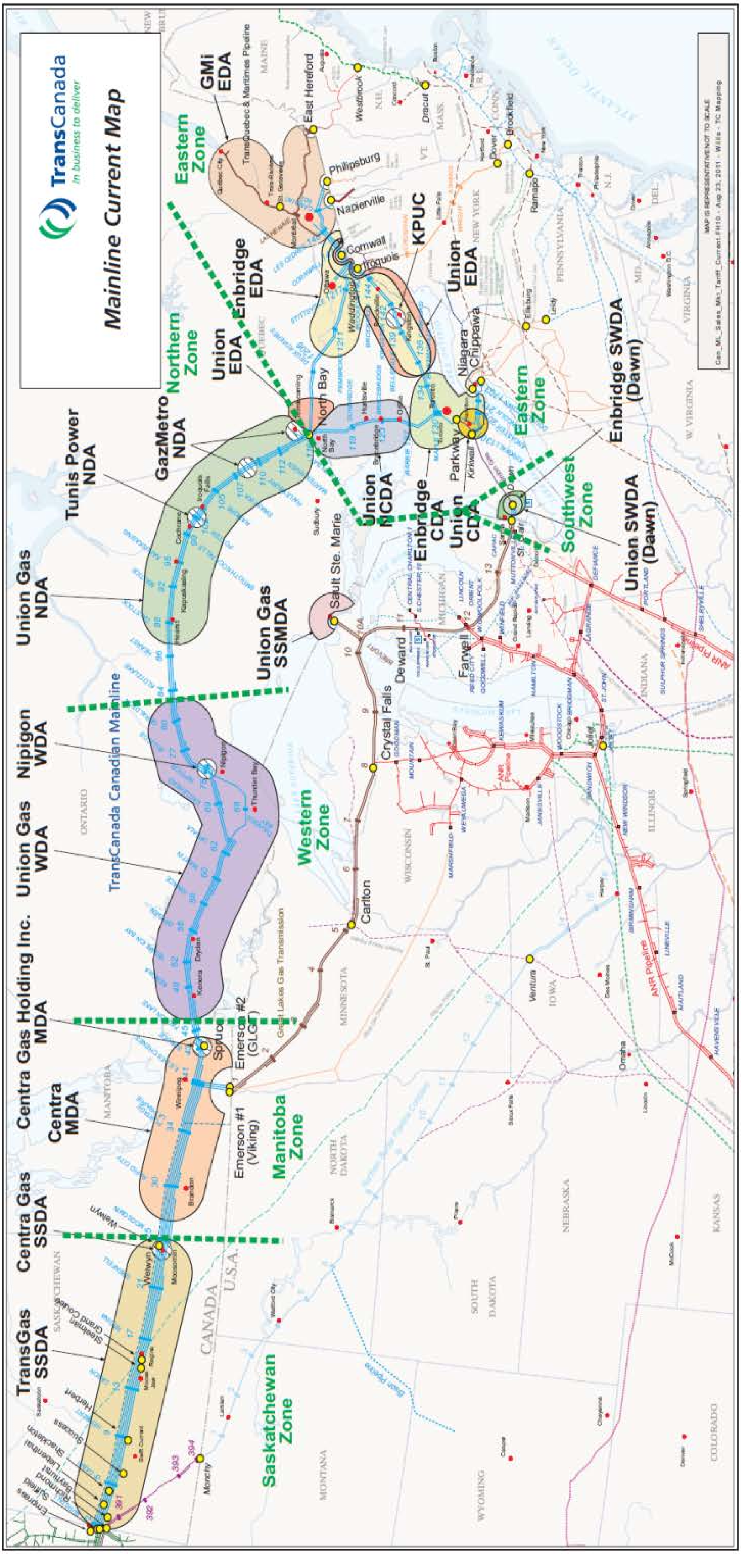
$ (millions)		Third Party Involvement	Incremental PGVA Impact	Transactional Services Revenue	Ratepayer Share
Option 1	Diversion of excess supply to Storage	No	-	-	-
Option 2	Base Exchange	Yes	-	(3.82)	(2.87)
Option 3	Capacity Release Exchange	Yes	-	(18.63)	(13.97)
Option 4	Utilization of FT RAM Credits	No	(1.86)	-	(1.86)

38. Asset optimization through transactional services ultimately benefits ratepayers through reduced rates. It has been a long established practice to incent the utility to maximize these transactions for the benefit of ratepayers through a revenue sharing mechanism. Capacity release exchange transactions are unplanned, a third party is requesting a service and EGD has temporarily surplus capacity available to accommodate them. If EGD had chosen the alternative discussed earlier of using FT-RAM for “own use” for storage injections, like it does for STS-RAM, the gas cost reduction generated for ratepayers would have been far less than the ratepayers portion of transactional services revenue that was generated from capacity release exchanges. EGD’s capacity release transactions, like base exchanges and STS-RAM credit exchanges, meet the elements of transactional

services and respond to the incentives to maximize transportation services revenue for the benefit of ratepayers as intended by design.

Witnesses: J. LeBlanc
D. Small
M. Giridhar

TransCanada Mainline



	$ 000's
Storage Optimization	4,702.6
Transportation Optimization	
- Exchange Revenue	20,814.8
- Capacity Release Net Revenue	18,629.8
- Incurred/avoided fuel costs	(28.2)
	39,416.5
Ratepayer Portion of Storage Optimization - 90 %	4,232.3
Ratepayer Portion of Transportation Optimization - 75 %	29,562.4
Ratepayer Portion of TS	33,794.7
Less 2012 Guarantee in Rates	8,000.0
	25,794.7
ETT Revenue - Rider H	275.4
TSDA Total	26,070.1
TSDA Clearance - Storage	3,505.8
TSDA Clearance - Transportation	22,564.2
	26,070.1

Item #	Transportation	Route	Contracted Daily Volume								
			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9
			Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
	GJ's										
1	TCPL FT - CDA	Empress to CDA	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468
2	Direct Purchase Assignment	Empress to CDA	(8,112)	(7,058)	(7,046)	(7,029)	(6,911)	(6,919)	(6,964)	(6,689)	(6,684)
3	TCPL FT - EDA	Empress to EDA	197,421	197,421	197,421	197,421	197,421	197,421	197,421	197,421	197,421
4	Direct Purchase Assignment	Empress to EDA	(11,386)	(11,307)	(11,021)	(11,048)	(10,989)	(11,043)	(10,968)	(10,931)	(10,927)
5	Transactional Services Capacity Release	Empress to EDA	(75,000)	(85,275)	(85,275)	(85,275)	(85,275)	(85,275)	(85,275)	(25,043)	-
6	TCPL FT - Iroquois	Empress to Iroquois	26,956	26,956	26,956	26,956	26,956	26,956	26,956	-	-
7	Transactional Services Capacity Release	Empress to Iroquois	(26,956)	(26,956)	(26,956)	(26,956)	(26,956)	(26,956)	(26,956)		
8	TCPL STFT - CDA	Empress to CDA	-	-	-	-	-	-	-	42,500	42,500
9	TCPL STFT - EDA	Empress to EDA	-	-	-	-	-	-	-	-	-
10	TCPL FT Dawn to CDA		149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818
11	Direct Purchase Assignment as per System Reliability		(44,533)	(44,533)	(44,533)	(44,533)	(44,533)	(44,533)	(44,533)	(42,232)	(42,232)
12	TCPL FT Dawn to EDA		114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
13	Tranasactional Services Assignment		(12,200)	(12,200)	(12,200)	(12,200)	(12,200)	(12,200)	(12,200)	-	-
14	TCPL FT Dawn to Iroquois		40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
15	TCPL FT-SN Parkway to CDA		85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
16	TCPL STS Parkway to CDA		284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464
17	TCPL STS Parkway to EDA		80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611
18	Union Gas Dawn to Parkway		2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173
19	Union Gas Dawn to Kirkwall		67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929
	$ (000's)										
20	Transactional Services Revenue - credit received from TCPL		7,131.4	7,848.2	7,831.8	7,848.2	7,848.2	7,831.8	7,848.2	1,707.0	-
21	Transactional Services Expense - amount paid to counterparty		(4,685.2)	(5,241.0)	(5,071.9)	(5,241.0)	(5,241.0)	(5,071.9)	(5,340.2)	(1,373.0)	-
22	Transactional Services Net Revenue		2,446.2	2,607.3	2,759.9	2,607.3	2,607.3	2,759.9	2,508.1	334.0	-
23	TCPL IT costs - Before STS RAM Credits		228.6	86.6	38.8	41.4	58.9	38.8	7.8	420.1	470.7
24	TCPL STS RAM Credits		(214.7)	-	-	-	-	-	-	(342.5)	(436.6)
25	Net Cost		13.9	86.6	38.8	41.4	58.9	38.8	7.8	77.6	34.2
26	Amount charged to Gas Cost		0.7	86.6	38.8	41.4	58.9	38.8	7.8	33.9	-
27	Amount charged as Transactional Services Expense		13.1	-	-	-	-	-	-	43.7	34.2
			13.9	86.6	38.8	41.4	58.9	38.8	7.8	77.6	34.2
28	Associated Transactional Services Revenue		120.4	-	-	-	-	-	-	11.3	14.7
29	Transactional Services Net Revenue		107.2	-	-	-	-	-	-	(32.4)	(19.5)

Item #	Empress to EDA	Total Release in the month of April 12	Total Release in the month of May 12	Total Release in the month of June 12	Total Release in the month of July 12	Total Release in the month of August 12	Total Release in the month of September 12	Total Release in the month of October 12	Total Release in the month of November 12	
		GJ	GJ	GJ	GJ	GJ	GJ	GJ	GJ	
1	FT Capacity Released	2,250,000	2,643,525	2,558,250	2,643,525	2,643,525	2,558,250	2,643,525	751,290	18,691,890
	Transportation Charges	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	
2	Empress to Eastern Zone FT Demand Toll	4,788.6	5,444.7	5,444.7	5,444.7	5,444.7	5,444.7	5,444.7	1,547.4	
3	FT RAM Credit	(5,227.7)	(6,142.0)	(5,943.9)	(6,142.0)	(6,142.0)	(5,943.9)	(6,142.0)	(1,745.6)	
4	Empress to Southwest Zone IT Toll	4,685.0	5,504.5	5,326.9	5,504.5	5,504.5	5,326.9	5,504.5	1,564.4	
5	Net Transportation Cost	4,246.0	4,807.1	4,827.7	4,807.1	4,807.1	4,827.7	4,807.1	1,366.2	
6	Net Transportation Savings	542.6	637.5	617.0	637.5	637.5	617.0	637.5	181.2	
7	Avg per unit savings - $/Gj	0.2412	0.2412	0.2412	0.2412	0.2412	0.2412	0.2412	0.2412	
8	Additional volume that could be moved through IT (Gj's)	260,603	306,183	296,306	306,183	306,183	296,306	306,183	87,017	

	Empress to Iroquois	Total Release in the month of April 12	Total Release in the month of May 12	Total Release in the month of June 12	Total Release in the month of July 12	Total Release in the month of August 12	Total Release in the month of September 12	Total Release in the month of October 12	Total Release in the month of November 12	
		GJ	GJ	GJ	GJ	GJ	GJ	GJ	GJ	
9	FT Capacity Released	808,680	835,636	808,680	835,636	835,636	808,680	835,636	-	5,768,584
	Transportation Charges	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	$(000's)	
10	Empress to Eastern Zone FT Demand Toll	1,675.4	1,731.3	1,675.4	1,731.3	1,731.3	1,675.4	1,731.3	-	
11	FT RAM Credit	(1,829.1)	(1,890.0)	(1,829.1)	(1,890.0)	(1,890.0)	(1,829.1)	(1,890.0)	-	
12	Empress to Southwest Zone IT Toll	1,683.9	1,740.0	1,683.9	1,740.0	1,740.0	1,683.9	1,740.0	-	
13	Net Transportation Cost	1,530.2	1,581.2	1,530.2	1,581.2	1,581.2	1,530.2	1,581.2	-	
14	Net Transportation Savings	145.2	150.0	145.2	150.0	150.0	145.2	150.0	-	
15	Avg per unit savings - $/Gj	0.1796	0.1796	0.1796	0.1796	0.1796	0.1796	0.1796	-	
16	Additional volume that could be moved through IT (Gj's)	69,732	72,057	69,732	72,057	72,057	69,732	72,057	-	
17	Total Volume that could have been transported at no charge	330,335	378,239	366,038	378,239	378,239	366,038	378,239	87,017	
18	Dawn/Empress Spread $/GJ	(0.90)	(0.76)	(0.48)	(0.81)	(0.78)	(0.56)	(0.62)	(0.75)	
19	Gas Cost Savings - $ 000's	(297.8)	(286.5)	(173.9)	(308.2)	(295.2)	(206.3)	(232.8)	(65.3)	(1,865.8)
20	Revenue from Capacity Release Exchange - $ 000's	2,446.2	2,607.3	2,759.9	2,607.3	2,607.3	2,759.9	2,508.1	334.0	18,629.8
21	Rate Payer share of Transactional Services Revenue from Capacity Release Exchanges - $ 000's									13,972.4
22	Asssumed Volume available for Base Exchanges - GJ's									24,460,474
23	Estimated Exchange fee $/GJ									0.156
24	Potential Transactional Services Revenue from Base Exchanges - $ 000's									3,821.9
25	Potential Rate Payer share of Transactional Services Revenue from Base Exchanges- $ 000's									2,866.4

Clearance of 2012 Deferral and Variance Account Balances

1. The Company is proposing to clear 2012 deferral and variance account balances to customers during the January 2014 billing cycle.

2. The unit rates for each type of service are shown at Exhibit C, Tab 2, Schedule 2, page 1. These unit rates will be applied to each customer's actual 2012 consumption volume for the period January 1, 2012 to December 31, 2012, and will be recovered or remitted in January 2014.

3. 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 2012 deferral and variance account;
   - Page 3 allocates account balances to the rate classes based on cost drivers for each type of account;
   - Page 4 summarizes the allocation of account balances by rate class and type of service; and
   - Page 5 derives the unit rates for the clearance / disposition by rate class and type of service. The unit rates are derived using actual 2012 consumption volumes for each rate class and each type of service.

4. The table on page 6 displays the bill adjustments in January 2014 for typical customers resulting from the clearance of the 2012 deferral and account balances. These bill adjustments will be shown as a separate line item on customers' January 2014 bills.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

<u>Other:</u>

5. In EB-2011-0277, the Company requested establishment of a Transition Impact of Accounting Change Deferral Account ("TIACDA") to recognize and record the financial impacts occurring in relation to the Company's required transition away from Canadian Generally Accepted Accounting Principles ("CGAAP"). This will be the first year clearing an amount recorded in the TIACDA.

6. The Company proposes to allocate the TIACDA amount proportionally to the allocation of the 2012 Distribution Revenue Requirement ("DRR") for each rate class. The nature of the cost within the TIACDA balance relates to pension benefits. Pension benefits follow labor within Operation and Maintenance (O&M) costs. O&M costs support all facets of utility operations. Consequently, the Company is proposing that the allocation of TIACDA balance represent utility operations as a whole. From that standpoint, the DRR allocation to the various rate classes is the most comprehensive representation of the distribution of costs to each rate class.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

UNIT RATE AND TYPE OF SERVICE: CLEARING IN JANUARY 2014

		COL.1 TOTAL (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	(0.4100)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0903)
	- WESTERN T-SERVICE	(0.4100)
RATE 6	- SYSTEM SALES	(0.1354)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1843
	- WESTERN T-SERVICE	(0.1354)
RATE 9	- SYSTEM SALES	(0.6204)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.3007)
	- WESTERN T-SERVICE	0.0000
RATE 100	- SYSTEM SALES	0.1147
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.4344
	- WESTERN T-SERVICE	0.1147
RATE 110	- SYSTEM SALES	(0.4054)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0857)
	- WESTERN T-SERVICE	(0.4054)
RATE 115	- SYSTEM SALES	(0.4727)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.1530)
	- WESTERN T-SERVICE	(0.4727)
RATE 135	- SYSTEM SALES	(0.1023)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.2174
	- WESTERN T-SERVICE	(0.1023)
RATE 145	- SYSTEM SALES	(0.8625)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.5428)
	- WESTERN T-SERVICE	(0.8625)
RATE 170	- SYSTEM SALES	(0.2351)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0846
	- WESTERN T-SERVICE	(0.2351)
RATE 200	- SYSTEM SALES	(0.3554)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0356)
	- WESTERN T-SERVICE	0.0000
Unbundled Services:		
RATE 125	- All	(0.7677)
	- Customer-specific ($)	$20,631
RATE 300	- All	(6.9630)

Determination of Balances to be Cleared
from the 2012 Deferral and Variance Accounts

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL For CLEARING ($000)
1.	**TRANSACTIONAL SERVICES D/A**	(26,077.3)	(495.1)	(26,572.4)
2.	**UNACCOUNTED FOR GAS V/A**	2,067.9	30.1	2,098.0
3.	**STORAGE AND TRANSPORTATION D/A**	(699.8)	(15.5)	(715.3)
4.	**DEFERRED REBATE ACCOUNT**	(940.8)	(16.6)	(957.4)
5.	**DEMAND SIDE MANAGEMENT 2011**	535.8	(40.5)	495.3
6.	**LOST REVENUE ADJ MECHANISM 2011**	(55.3)	(0.5)	(55.8)
7.	**SHARED SAVINGS MECHANISM 2011**	6,769.5	41.5	6,811.0
8.	**ONTARIO HEARING COSTS V/A**	(1,259.7)	(19.2)	(1,278.9)
9.	**GAS DISTRIBUTION ACCESS RULE D/A 2012**	1,097.8	0.0	1,097.8
10.	**AVERAGE USE TRUE-UP V/A**	4,361.3	63.7	4,425.0
11.	**ELECTRIC PROGRAM EARNINGS SHARING D/A**	(281.7)	(3.7)	(285.4)
12.	**UNBUNDLED RATE IMPLEMENTATION COST D/A**	155.0	3.3	158.3
13.	**MUNICIPAL PERMIT FEES D/A**			0.0
14.	**OPEN BILL SERVICE D/A**			0.0
15.	**OPEN BILL ACCESS V/A**			0.0
16.	**EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A**	(143.0)	(2.3)	(145.3)
17.	**TAX RATE & RULE CHANGE V/A**	300.0	5.0	305.0
18.	**TRANSITION IMPACT OF ACCT CHANGE D/A**	4,435.8		4,435.8
19.	**EARNINGS SHARING MECHANISM**	(10,350.0)	(152.3)	(10,502.3)
20.	**TOTAL**	(20,084.4)	(602.1)	(20,686.5)

Classification and Allocation of Deferral and Variance Account Balances

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										
	PGVA:										
1.1	COMMODITY	0.0		0.0							
1.2	SEASONAL PEAKING-LOAD BALANCING	0.0					0.0				
1.3	SEASONAL DISCRETIONARY-LOAD BALANCING	0.0				0.0					
1.4	TRANSPORTATION TOLLS	0.0	0.0								
1.5	CURTAILMENT REVENUE	0.0					0.0		0.0		
1.6	RIDER C 2009 DIRECT ALLOCATION	0.0							0.0		
1.7	INVENTORY ADJUSTMENT	0.0									
1.		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.	**TRANSACTIONAL SERVICES D/A**	(26,572.4)	(22,934.3)			(1,718.4)	(1,919.7)				
2.	**UNACCOUNTED FOR GAS V/A**	2,098.0			2,098.0						
3.	**STORAGE AND TRANSPORTATION D/A**	(715.3)				(337.9)	(377.4)				
4.	**DEFERRED REBATE ACCOUNT**	(957.4)			(957.4)						
5.	**DEMAND SIDE MANAGEMENT 2010**	495.3							495.3		
6.	**LOST REVENUE ADJ MECHANISM 2010**	(55.8)							(55.8)		
7.	**SHARED SAVINGS MECHANISM 2010**	6,811.0							6,811.0		
8.	**CLASS ACTION SUIT D/A**	0.0								0.0	
9.	**ONTARIO HEARING COSTS V/A**	(1,278.9)									(1,278.9)
10.	**GAS DISTRIBUTION ACCESS RULE D/A**	1,097.8								1,097.8	
11.	**AVERAGE USE TRUE-UP V/A**	4,425.0							4,425.0		
12.	**ELECTRIC PROGRAM EARNINGS SHARING D/A**	(285.4)									(285.4)
13.	**UNBUNDLED RATE IMPLEMENTATION COST D/A**	158.3								158.3	
14.	**MUNICIPAL PERMIT FEES D/A**	0.0									0.0
15.	**OPEN BILL SERVICE D/A**	0.0								0.0	
16.	**OPEN BILL ACCESS V/A**	0.0								0.0	
17.	**EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A**	(145.3)								(145.3)	
18.	**TAX RATE & RULE CHANGE V/A**	305.0									305.0
19.	**MEAN DAILY VOLUME MECHANISM D/A**	4,435.8						4,435.8		0.0	
20.	**EARNINGS SHARING MECHANISM**	(10,502.3)						(10,502.3)			
21.	**TOTAL**	(20,686.5)	(22,934.3)	0.0	1,140.6	(2,056.3)	(2,297.1)	(6,066.5)	11,675.6	1,110.8	(1,259.3)
	ALLOCATION										
1.1	RATE 1	(15,931.1)	(12,117.4)	0.0	460.3	(978.4)	(1,255.1)	(4,110.5)	2,052.3	876.7	(859.1)
1.2	RATE 6	(1,634.6)	(9,407.8)	0.0	459.4	(948.0)	(992.5)	(1,742.9)	11,279.6	75.5	(358.0)
1.3	RATE 9	(4.2)	(2.0)	0.0	0.1	0.0	0.0	(1.6)	0.0	0.0	(0.7)
1.4	RATE 100	9.4	(6.5)	0.0	0.4	(0.8)	(0.9)	(1.5)	17.8	1.2	(0.3)
1.5	RATE 110	(1,087.9)	(535.2)	0.0	70.3	(26.3)	(19.3)	(57.9)	(543.2)	35.4	(11.7)
1.6	RATE 115	(824.9)	(51.6)	0.0	55.1	(0.1)	(5.7)	(26.1)	(795.6)	4.8	(5.7)
1.7	RATE 125	12.5	0.0	0.0	0.0	0.0	0.0	(59.8)	0.0	83.2	(10.9)
1.8	RATE 135	43.1	(79.8)	0.0	6.2	0.0	0.0	(5.9)	116.5	6.9	(0.7)
1.9	RATE 145	(1,043.0)	(156.5)	0.0	17.8	(23.9)	0.0	(20.8)	(875.5)	19.5	(3.6)
1.10	RATE 170	226.0	(187.0)	0.0	53.2	(45.4)	0.0	(20.3)	423.7	6.4	(4.6)
1.11	RATE 200	(449.1)	(390.5)	0.0	17.9	(33.4)	(23.6)	(16.5)	0.0	0.2	(3.2)
1.12	RATE 300	(2.6)	0.0	0.0	0.0	0.0	0.0	(2.8)	0.0	0.9	(0.7)
1.		(20,686.5)	(22,934.3)	0.0	1,140.6	(2,056.3)	(2,297.1)	(6,066.5)	11,675.6	1,110.8	(1,259.3)

ALLOCATION BY TYPE OF SERVICE

		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	(14,479.5)	(11,291.8)	0.0	384.8	(817.8)	(1,049.1)	(3,435.8)	1,715.4	732.8	(718.1)
	- 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	(392.9)			47.4	(100.8)	(129.3)	(423.5)	211.4	90.3	(88.5)
	- WBT	(1,058.7)	(825.6)		28.1	(59.8)	(76.7)	(251.2)	125.4	53.6	(52.5)
RATE 6	- SYSTEM SALES	(3,022.3)	(7,137.4)	0.0	243.2	(501.9)	(525.5)	(922.7)	5,971.4	40.0	(189.5)
	- 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	2,349.0			138.8	(286.5)	(299.9)	(526.7)	3,408.7	22.8	(108.2)
	- WBT	(961.4)	(2,270.4)		77.4	(159.6)	(167.1)	(293.5)	1,899.5	12.7	(60.3)
RATE 9	- SYSTEM SALES	(4.0)	(2.0)	0.0	0.1	0.0	0.0	(1.4)	0.0	0.0	(0.6)
	- 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	(0.3)			0.0	0.0	0.0	(0.2)	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
RATE 100	- SYSTEM SALES	1.7	(4.8)	0.0	0.2	(0.3)	(0.4)	(0.6)	7.3	0.5	(0.1)
	- 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	7.1			0.2	(0.4)	(0.4)	(0.7)	7.9	0.6	(0.1)
	- WBT	0.6	(1.7)		0.1	(0.1)	(0.1)	(0.2)	2.6	0.2	(0.0)
RATE 110	- SYSTEM SALES	(357.7)	(282.1)	0.0	9.6	(3.6)	(2.6)	(7.9)	(74.3)	4.8	(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	(409.2)			52.0	(19.4)	(14.3)	(42.8)	(402.2)	26.2	(8.7)
	- WBT	(321.0)	(253.2)		8.6	(3.2)	(2.4)	(7.1)	(66.7)	4.3	(1.4)
RATE 115	- SYSTEM SALES	(4.4)	(2.9)	0.0	0.1	(0.0)	(0.0)	(0.0)	(1.4)	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	(748.7)			53.3	(0.1)	(5.5)	(25.2)	(770.2)	4.6	(5.6)
	- WBT	(71.9)	(48.7)		1.7	(0.0)	(0.2)	(0.8)	(23.9)	0.1	(0.2)
RATE 135	- SYSTEM SALES	(1.3)	(4.0)	0.0	0.1	0.0	0.0	(0.1)	2.6	0.2	(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	68.7			3.4	0.0	0.0	(3.3)	65.1	3.9	(0.4)
	- WBT	(24.3)	(75.8)		2.6	0.0	0.0	(2.5)	48.9	2.9	(0.3)
RATE 145	- SYSTEM SALES	(195.4)	(72.4)	0.0	2.5	(3.3)	0.0	(2.9)	(121.4)	2.7	(0.5)
	- 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	(620.8)			12.5	(16.7)	0.0	(14.5)	(613.1)	13.6	(2.5)
	- WBT	(226.9)	(84.1)		2.9	(3.8)	0.0	(3.3)	(141.0)	3.1	(0.6)
RATE 170	- SYSTEM SALES	(106.0)	(144.2)	0.0	4.9	(4.2)	0.0	(1.9)	39.2	0.6	(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	363.5			46.8	(40.0)	0.0	(17.8)	373.0	5.6	(4.1)
	- WBT	(31.4)	(42.7)		1.5	(1.2)	0.0	(0.6)	11.6	0.2	(0.1)
RATE 200	- SYSTEM SALES	(434.0)	(390.5)	0.0	13.3	(24.8)	(17.5)	(12.3)	0.0	0.1	(2.4)
	- 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	(15.1)			4.6	(8.6)	(6.1)	(4.3)	0.0	0.0	(0.8)
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbundled Services:											
RATE 125		12.5	0.0	0.0	0.0	0.0	0.0	(59.8)	0.0	83.2	(10.9)
RATE 300		(2.6)	0.0	0.0	0.0	0.0	0.0	(2.8)	0.0	0.9	(0.7)
		(20,686.5)	(22,934.3)	0.0	1,140.6	(2,056.3)	(2,297.1)	(6,066.5)	11,675.6	1,110.8	(1,259.3)

UNIT RATE AND TYPE OF SERVICE

		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	(0.4100)	(0.3197)	0.0000	0.0109	(0.0232)	(0.0297)	(0.0973)	0.0486	0.0207	(0.0203)	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	(0.0903)			0.0109	(0.0232)	(0.0297)	(0.0973)	0.0486	0.0207	(0.0203)	0.0000
	- WESTERN T-SERVICE	(0.4100)	(0.3197)		0.0109	(0.0232)	(0.0297)	(0.0973)	0.0486	0.0207	(0.0203)	0.0000
RATE 6	- SYSTEM SALES	(0.1354)	(0.3197)	0.0000	0.0109	(0.0225)	(0.0235)	(0.0413)	0.2675	0.0018	(0.0085)	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	0.1843			0.0109	(0.0225)	(0.0235)	(0.0413)	0.2675	0.0018	(0.0085)	0.0000
	- WESTERN T-SERVICE	(0.1354)	(0.3197)		0.0109	(0.0225)	(0.0235)	(0.0413)	0.2675	0.0018	(0.0085)	0.0000
RATE 9	- SYSTEM SALES	(0.6204)	(0.3197)	0.0000	0.0109	0.0000	0.0000	(0.2146)	0.0000	0.0006	(0.0976)	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	(0.3007)			0.0109	0.0000	0.0000	(0.2146)	0.0000	0.0006	(0.0976)	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	0.1147	(0.3197)	0.0000	0.0109	(0.0222)	(0.0235)	(0.0413)	0.4853	0.0338	(0.0085)	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	0.4344			0.0109	(0.0222)	(0.0235)	(0.0413)	0.4853	0.0338	(0.0085)	0.0000
	- WESTERN T-SERVICE	0.1147	(0.3197)		0.0109	(0.0222)	(0.0235)	(0.0413)	0.4853	0.0338	(0.0085)	0.0000
RATE 110	- SYSTEM SALES	(0.4054)	(0.3197)	0.0000	0.0109	(0.0041)	(0.0030)	(0.0090)	(0.0842)	0.0055	(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	(0.0857)			0.0109	(0.0041)	(0.0030)	(0.0090)	(0.0842)	0.0055	(0.0018)	0.0000
	- WESTERN T-SERVICE	(0.4054)	(0.3197)		0.0109	(0.0041)	(0.0030)	(0.0090)	(0.0842)	0.0055	(0.0018)	0.0000
RATE 115	- SYSTEM SALES	(0.4727)	(0.3197)	0.0000	0.0109	(0.0000)	(0.0011)	(0.0052)	(0.1574)	0.0009	(0.0011)	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	(0.1530)			0.0109	(0.0000)	(0.0011)	(0.0052)	(0.1574)	0.0009	(0.0011)	0.0000
	- WESTERN T-SERVICE	(0.4727)	(0.3197)		0.0109	(0.0000)	(0.0011)	(0.0052)	(0.1574)	0.0009	(0.0011)	0.0000
RATE 135	- SYSTEM SALES	(0.1023)	(0.3197)	0.0000	0.0109	0.0000	0.0000	(0.0105)	0.2059	0.0122	(0.0012)	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	0.2174			0.0109	0.0000	0.0000	(0.0105)	0.2059	0.0122	(0.0012)	0.0000
	- WESTERN T-SERVICE	(0.1023)	(0.3197)		0.0109	0.0000	0.0000	(0.0105)	0.2059	0.0122	(0.0012)	0.0000
RATE 145	- SYSTEM SALES	(0.8625)	(0.3197)	0.0000	0.0109	(0.0146)	0.0000	(0.0127)	(0.5361)	0.0119	(0.0022)	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	(0.5428)			0.0109	(0.0146)	0.0000	(0.0127)	(0.5361)	0.0119	(0.0022)	0.0000
	- WESTERN T-SERVICE	(0.8625)	(0.3197)		0.0109	(0.0146)	0.0000	(0.0127)	(0.5361)	0.0119	(0.0022)	0.0000
RATE 170	- SYSTEM SALES	(0.2351)	(0.3197)	0.0000	0.0109	(0.0093)	0.0000	(0.0042)	0.0868	0.0013	(0.0009)	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	0.0846			0.0109	(0.0093)	0.0000	(0.0042)	0.0868	0.0013	(0.0009)	0.0000
	- WESTERN T-SERVICE	(0.2351)	(0.3197)		0.0109	(0.0093)	0.0000	(0.0042)	0.0868	0.0013	(0.0009)	0.0000
RATE 200	- SYSTEM SALES	(0.3554)	(0.3197)	0.0000	0.0109	(0.0203)	(0.0143)	(0.0100)	0.0000	0.0001	(0.0020)	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	(0.0356)			0.0109	(0.0203)	(0.0143)	(0.0100)	0.0000	0.0001	(0.0020)	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	(0.7677)	0.0000	0.0000	0.0000	0.0000	0.0000	(0.6560)	0.0000	0.0077	(0.1194)	0.0000
	- Customer-specific **											20.6311
RATE 300	- All	(6.9630)	0.0000	0.0000	0.0000	0.0000	0.0000	(7.4746)	0.0000	2.3627	(1.8511)	0.0000

Notes:
* Unit Rates derived based on 2012 actual volumes
** The Company incurred $82.5k in additional staffing costs in 2012 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 2011 and the costs were allocated equally among the three customers.

Enbridge Gas Distribution Inc.
2012 Deferral and Variance Account Clearing
Bill Adjustment in January 2014 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	(0.4100)	(0.0903)	(0.4100)	(12.6)	(2.8)	(12.6)
2.1	**RATE 6 COMMERCIAL**							
2.2	General Use	43,285	(0.1354)	0.1843	(0.1354)	(59)	80	(59)
	CONTRACT SERVICE							
3.1	**RATE 100**							
3.2	Industrial - small size	339,188	0.1147	0.4344	0.1147	389	1,473	389
4.1	**RATE 110**							
4.2	Industrial - small size, 50% LF	598,568	(0.4054)	(0.0857)	(0.4054)	(2,427)	(513)	(2,427)
4.5	Industrial - avg. size, 75% LF	9,976,120	(0.4054)	(0.0857)	(0.4054)	(40,443)	(8,547)	(40,443)
5.1	**RATE 115**							
5.2	Industrial - small size, 80% LF	4,471,609	(0.4727)	(0.1530)	(0.4727)	(21,137)	(6,840)	(21,137)
6.1	**RATE 135**							
6.2	Industrial - Seasonal Firm	598,567	(0.1023)	0.2174	(0.1023)	(612)	1,301	(612)
7.1	**RATE 145**							
7.2	Commercial - avg. size	598,568	(0.8625)	(0.5428)	(0.8625)	(5,163)	(3,249)	(5,163)
8.1	**RATE 170**							
8.2	Industrial - avg. size, 75% LF	9,976,120	(0.2351)	0.0846	(0.2351)	(23,453)	8,443	(23,453)

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

ENBRIDGE

ENBRIDGE GAS DISTRIBUTION INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2012

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Distribution Inc.

Financial Reporting
Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and necessarily include amounts that reflect management's judgment and best estimates

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, which includes directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC 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 AF&RC 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 shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

D. Guy Jarvis
President

(Signed)

Narinder K. Kishinchandani
Vice President, Finance

February 14, 2013

February 14, 2013

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, 2012 and December 31, 2011 and the consolidated statements of earnings, comprehensive income, changes in shareholders' equity and cash flows for each of the three years in the period ended December 31, 2012, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

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 accounting principles generally accepted in the United States of America 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 audits 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.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215, www.pwc.com/ca

pwc

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, 2012 and December 31, 2011 and its results of operations and its cash flows for each of the three years in the period ended December 31, 2012 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Gas commodity and distribution revenue *(Note 20)*	**1,869**	1,880	1,781
Transportation of gas for customers	**345**	421	458
	2,214	2,301	2,239
Gas commodity and distribution costs, excluding depreciation *(Note 20)*	**(1,199)**	(1,268)	(1,236)
Gas distribution margin	**1,015**	1,033	1,003
Other revenue *(Note 4)*	**202**	103	110
	1,217	1,136	1,113
Expenses			
Operating and administrative *(Note 20)*	**449**	437	406
Depreciation and amortization	**320**	302	292
Municipal and other taxes	**40**	41	44
Earnings sharing *(Note 4)*	**10**	13	19
	819	793	761
	398	343	352
Affiliate financing income *(Note 20)*	**63**	63	63
Interest expense *(Notes 11 and 20)*	**(170)**	(172)	(186)
	291	234	229
Income taxes *(Note 17)*			
Current	**(41)**	(52)	(59)
Deferred	**(20)**	9	6
	(61)	(43)	(53)
Earnings from continuing operations	**230**	191	176
Discontinued operations *(Note 5)*			
Earnings from discontinued operations before income taxes	**6**	2	-
Income taxes from discontinued operations	**(2)**	-	-
Earnings from discontinued operations	**4**	2	-
Earnings	**234**	193	176
Preference share dividends	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**232**	191	174

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Earnings	**234**	193	176
Other comprehensive (loss)/income, net of tax *(Note 15)*			
Change in unrealized loss on cash flow hedges	**(1)**	(1)	(17)
Actuarial loss on other postretirement benefits	**(3)**	(10)	(3)
Reclassification to earnings of realized loss on cash flow hedges	**2**	2	2
Change in foreign currency translation adjustment	**-**	-	(1)
Other comprehensive loss	**(2)**	(9)	(19)
Comprehensive income	**232**	184	157
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**230**	182	155

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Preference shares *(Note 13)*	**100**	100	100
Common shares *(Note 13)*			
Balance at beginning of year	**1,137**	1,071	1,071
Common shares issued	**-**	66	-
Balance at end of year	**1,137**	1,137	1,071
Additional paid-in capital			
Balance at beginning of year	**1,131**	1,131	1,131
Disposition *(Note 5)*	**17**	-	-
Balance at end of year	**1,148**	1,131	1,131
Retained earnings			
Balance at beginning of year	**32**	61	102
Earnings attributable to the common shareholder	**232**	191	174
Common share dividends declared	**(201)**	(220)	(215)
Balance at end of year	**63**	32	61
Accumulated other comprehensive loss *(Note 15)*			
Balance at beginning of year	**(24)**	(15)	4
Other comprehensive loss	**(2)**	(9)	(19)
Balance at end of year	**(26)**	(24)	(15)
Total shareholders' equity	**2,422**	2,376	2,348

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Operating activities			
Earnings	**234**	193	176
Earnings from discontinued operations	**(4)**	(2)	-
Depreciation and amortization	**320**	302	292
Deferred income taxes	**20**	(9)	(6)
Recognition of regulatory asset	**(89)**	-	-
Other	**8**	7	5
Changes in operating assets and liabilities *(Note 19)*	**77**	15	45
Cash provided by continuing operations	**566**	506	512
Cash provided by discontinued operations	**12**	3	-
	578	509	512
Investing activities			
Proceeds from sale of assets *(Note 5)*	**72**	-	-
Additions to property, plant and equipment	**(441)**	(441)	(345)
Additions to intangible assets	**(38)**	(34)	(20)
Change in construction payable	**(11)**	5	-
Other	**4**	9	-
Cash used in continuing operations	**(414)**	(461)	(365)
Financing activities			
Net change in bank overdraft	**(2)**	(10)	(11)
Net change in short-term borrowings	**35**	222	(182)
Net change in short-term note payable to affiliate company *(Note 20)*	**5**	2	(1)
Debenture and term note issues	**-**	100	402
Debenture and term note repayments	**-**	(150)	(150)
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(206)**	(218)	(208)
Other	**-**	4	(2)
Cash used in continuing operations	**(170)**	(52)	(154)
Decrease in cash and cash equivalents	**(6)**	(4)	(7)
Cash and cash equivalents at beginning of year	**9**	13	20
Cash and cash equivalents at end of year	**3**	9	13
Cash and cash equivalents – discontinued operations	**-**	(3)	-
Cash and cash equivalents – continuing operations	**3**	6	13
Supplementary cash flow information			
Income taxes paid	**31**	62	59
Interest paid *(Note 11)*	**176**	169	185

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2012**	2011
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**3**	6
Accounts receivable and other *(Notes 6, 17 and 20)*	**594**	659
Gas inventories	**326**	380
Assets associated with discontinued operations *(Note 5)*	**-**	7
	923	1,052
Property, plant and equipment, net *(Note 7)*	**5,532**	5,336
Investment in affiliate company *(Note 20)*	**825**	825
Deferred amounts and other assets *(Note 8)*	**432**	298
Intangible assets, net *(Note 9)*	**177**	170
Assets associated with discontinued operations *(Note 5)*	**-**	67
	7,889	7,748
Liabilities and shareholders' equity		
Current liabilities		
Bank overdraft	**5**	7
Short-term borrowings *(Note 11)*	**596**	556
Accounts payable and other *(Notes 10, 17 and 20)*	**648**	718
	1,249	1,281
Long-term debt *(Note 11)*	**2,387**	2,387
Other long-term liabilities *(Note 12)*	**1,094**	1,019
Deferred income taxes *(Note 17)*	**362**	304
Loans from affiliate company *(Notes 11 and 20)*	**375**	375
Liabilities associated with discontinued operations *(Notes 5 and 17)*	**-**	6
	5,467	5,372
Commitments and contingencies *(Notes 20 and 21)*		
Shareholders' equity		
Share capital *(Note 13)*		
Preference shares *(convertible; 4 outstanding at December 31, 2012 and 2011)*	**100**	100
Common shares *(142 outstanding at December 31, 2012 and 2011)*	**1,137**	1,137
Additional paid-in capital	**1,148**	1,131
Retained earnings	**63**	32
Accumulated other comprehensive loss *(Note 15)*	**(26)**	(24)
	2,422	2,376
	7,889	7,748

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

Approved by the Board of Directors:

(Signed)

D. Guy Jarvis
President

(Signed)

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

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).

The Company also owns and operates unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements of the Company are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative years. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under a three-year exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES
The preparation of consolidated financial statements in conformity with U.S. 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 4)*; unbilled revenues *(Note 6)*; allowance for doubtful accounts *(Note 6)*; depreciation rates and carrying value of property, plant and equipment *(Note 7)*; amortization rates and carrying value of intangible assets *(Note 9)*; valuation of stock- based compensation *(Note 14)*; fair value of financial instruments *(Note 16)*; provisions for income taxes *(Note 17)*; assumptions used to measure retirement and postretirement benefit obligations *(Note 18),* commitments and contingencies *(Note 21)*; and fair value of asset retirement obligations. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION
The consolidated financial statements include the accounts of the Company and its subsidiaries. All significant intercompany accounts and transactions are eliminated upon consolidation.

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 U.S. GAAP for non rate-regulated entities *(Note 4)*.

REVENUE RECOGNITION
The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and 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 approved by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

PUSH-DOWN ACCOUNTING

The Company has elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage changes 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 effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges at December 31, 2012 or 2011.

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/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

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 at that date is deferred in OCI and 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 derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives

The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

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 Deferred amounts and other assets. 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. Deferred 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. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

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

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/(loss) (AOCI). Asset and liability accounts are translated at the exchange rates on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

The Company extinguishes liabilities when a creditor has relieved the Company of its obligation, which occurs when the Company's financial institution honours a cheque that the creditor has presented for payment. Accordingly, obligations for which the Company has issued cheque payments that have not been presented to the financial institution are included in Accounts payable and other on the Consolidated Statements of Financial Position.

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 as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators.

Included in, or deducted from, physical 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, 2012, $65 million (2011 - $100 million) of natural gas was held on behalf of transportation service customers. These transactions have no impact on the Company's consolidated earnings or financial position.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

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. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. Depreciation of property, plant and equipment 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.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include: costs the Regulators have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; derivative financial instruments; and deferred financing costs. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges. Deferred financing costs are amortized using the effective interest method over the term of the related debt.

INTANGIBLE ASSETS

Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful 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 and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS

The Company maintains non-contributory pension plans which provide defined benefit and defined contribution pension benefits to the majority of its employees.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. During the year ended December 31, 2012, the Company refined the methodology by which it determines discount rates; in particular, refining the method by which it estimates spreads for bonds with longer term maturities. Pension cost includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets; and

- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on pension plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

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 invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contributions occur.

The Company also provides other postretirement benefits (OPEB) other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans are recognized on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation.

The regulated utility operations of the Company recovered pension and OPEB expense based on amounts paid, in accordance with the methodology accepted by the Regulators for rate-making purposes. As a result, rates typically only included the recovery of required contributions. Pursuant to an OEB decision in May 2012, the Company's 2012 pension contributions were not separately recovered in rates. A November 2012 rate order from the OEB provided for future pension and OPEB costs, determined on an accrual basis, to be recovered in rates.

The Company recorded pension expenditures on a cash basis. A corresponding pension regulatory asset/liability was recorded, reflecting the Company's ability to incorporate this amount in future rates. In the absence of rate regulation, this balance would not have been recorded and pension expenditures would have been charged to earnings and OCI on the accrual basis of accounting. Pension expenditures will be recorded on the accrual basis of accounting starting in 2013.

The Company has previously recorded and will continue to record OPEB expenditures on the accrual basis of accounting. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period related to OPEB are recognized as a component of OCI, net of income taxes.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

Incentive Stock Options (ISOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility.

Performance based stock options (PBSOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PBSOs granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period. The options become exercisable when both performance targets and time vesting requirements have been met.

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, an expense is recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMMITMENTS AND CONTINGENCIES

Liabilities for other commitments and contingencies are recognized when, after fully analyzing the available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

COMPARATIVE AMOUNTS

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

3. CHANGES IN ACCOUNTING POLICIES

FAIR VALUE MEASUREMENT

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the Financial Accounting Standard Board's joint project with the International Accounting Standards Board. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in the Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the Company does not hold any Level 3 instruments, the adoption of this update did not have an impact on the Company's consolidated financial statements.

STATEMENT OF COMPREHENSIVE INCOME

Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and OCI either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company's presentation of comprehensive income and did not impact the Company's consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Balance Sheet Offsetting

In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning on or after January 1, 2013.

4. 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 were set using a revenue per customer cap Incentive Regulation (IR) methodology for the 2008 to 2012 period. The IR methodology adjusted revenues, and consequently rates, annually and relied on an annual process to forecast volume and customer additions.

Enbridge Gas Distribution's 2013 rates, and St. Lawrence's rates for each year, are set using a cost of service (COS) methodology that allows revenues to be set to recover costs and to earn a rate of return on common equity. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, municipal and other 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 Enbridge Gas Distribution and St. Lawrence to demonstrate to the Regulators 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, 2012 (2011 – 8.39%) based on a 36% (2011 – 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 formed part of the Settlement Agreement (the Settlement) with customer representatives approved by the OEB in February 2008. The Settlement encompassed all major financial aspects of the IR methodology that operated for 2008 to 2012 (inclusive). To the extent the actual utility return on the approved equity level represented by normalized earnings based on Part V – Pre-changeover accounting standards of the Canadian Institute of Chartered Accountants Handbook (Canadian GAAP) (i.e., excluding the effects of weather) (ROE) exceeded the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings were shared with customers. The common shareholder retained 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 were shared equally with customers.

Enbridge Gas Distribution's rates for 2013, under a COS methodology, will include an after-tax rate of return on common equity of 8.93% based on a 36% deemed common equity component of capital for regulatory purposes.

St. Lawrence

St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2012 (2011 - 10.5%) based on a 50% (2011 - 50%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 11% (2011 - 11%) were shared equally with customers. The calculation of such earnings was 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, 2012 (2011 - nil). St. Lawrence will continue operating under the existing COS agreement in 2013.

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. 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. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

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. The Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from 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.

FINANCIAL STATEMENT EFFECTS

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

December 31,	**2012**	2011	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Deferred income taxes [1]	**198**	164	DA	*
Pension plans, net [2]	**115**	103	DA/OLTL	*
OPEB [3]	**89**	-	AR/DA	20
Purchased gas variance [4]	**11**	-	AR	1
Deferred rate hearing costs [5]	**5**	3	AP/DA	2
Average use true-up variance [6]	**4**	(3)	AR	*
Unaccounted for gas variance [7]	**2**	9	AR	1
Settlement recoverable [8]	**-**	5	AR	*
Future removal and site restoration reserves [9]	**(859)**	(815)	OLTL	*
Transactional services deferral [10]	**(26)**	(7)	AP	1
Earnings sharing deferral [11]	**(10)**	(14)	AP	1
Other regulatory assets and liabilities	**3**	2	***	***
	(468)	(553)		
St. Lawrence				
Other regulatory assets and liabilities	**8**	6	***	***
	8	6		
	(460)	(547)		

* 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 deferred income taxes balance represents the regulatory offset to deferred 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 the timing of the reversal of the temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

2 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

3 *The OPEB balance represents the Company's right to recover OPEB costs pursuant to an OEB rate order received in November 2012. The amount will be collected in rates on a straight-line basis over a 20-year period commencing in 2013. In the absence of rate regulation, this regulatory balance and related earnings impact would not be recorded.*

4 *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, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In the absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.*

5 *Deferred rate hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has historically 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.*

6 *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.*

7 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.

8 Settlement recoverable deferral represents amounts paid toward the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts were recovered from customers over a five-year period, which commenced in 2008. In the absence of rate regulation, these costs would have been 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 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.

11 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 Canadian GAAP earnings represented by the ROE in excess of 100 basis points above the NROE. The December 31, 2012 balance relates to the year ended December 31, 2012. The December 31, 2011 balance relates to the years ended December 31, 2011 and 2010. 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.

In November 2012, the Company received a rate order from the OEB permitting recovery of OPEB costs in the amount of $89 million. The amount will be collected in rates on a straight-line basis over a 20-year period commencing in 2013, and is presented within Other revenue in the Consolidated Statements of Earnings. In the absence of rate regulation, this earnings impact would not have been recorded.

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, 2012, costs relating to this services contract of $144 million (2011 - $133 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, 2012, the net book value of these costs was $86 million (2011 - $99 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. Included in gas inventories at December 31, 2012 is $39 million (2011 - $42 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 and inventory would be recorded at the lower of cost or market value.

Depreciation

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

5. DISPOSITION AND ACQUISITION

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund (the Fund), an affiliated entity under common control, for proceeds of $72 million. Project Amherstburg consisted primarily of property, plant and equipment and intangible assets. The excess of the sale price over the net book value at the time of disposition of $17 million inclusive of deferred income tax recoveries of $10 million were recognized as Additional paid-in capital. No gain or loss was recognized in earnings on the disposition; however $5 million of cash income taxes incurred on the related capital gain remains as a charge to consolidated earnings for the year ended December 31, 2012.

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. The total consideration transferred for Project Amherstburg was approximately $66 million, which was primarily funded by the issuance of common shares (1,612,367 shares).

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2012**	2011
(millions of Canadian dollars)		
Trade receivables	**321**	377
Unbilled revenues	**170**	176
Agent billing and collection receivable	**44**	69
Regulatory assets *(Note 4)*	**32**	24
Taxes receivable	**18**	19
Due from affiliates *(Note 20)*	**12**	12
Current deferred income taxes *(Note 17)*	**5**	-
Prepaid expenses	**4**	3
Other	**29**	24
Allowance for doubtful accounts	**(41)**	(45)
	594	659

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2012**	2011
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**4.2%**	**3,132**	2,985
Gas services	**4.6%**	**2,530**	2,418
Regulating and metering equipment	**3.8%**	**757**	719
Gas storage	**3.0%**	**295**	275
Land and right-of-way	**2.5%**	**78**	79
Computer technology	**19.3%**	**42**	35
Under construction	**-**	**102**	92
Construction materials inventory	**-**	**38**	39
Other	**3.6%**	**284**	259
		7,258	6,901
Accumulated depreciation		**(1,806)**	(1,649)
		5,452	5,252
Unregulated property, plant and equipment			
Gas storage	**3.0%**	**86**	88
Accumulated depreciation		**(6)**	(4)
		80	84
Property, plant and equipment, net		**5,532**	5,336

Depreciation expense, including amounts collected for future removal and site restoration costs, was $289 million for the year ended December 31, 2012 (2011 - $271 million, 2010 - $260 million).

8. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2012**	2011
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**414**	277
Deferred financing costs	**11**	13
Pension asset *(Note 18)*	**3**	2
Other	**4**	6
	432	298

At December 31, 2012, deferred amounts of $29 million (2011 - $29 million) were subject to amortization and are presented net of accumulated amortization of $18 million (2011 - $16 million). Amortization expense for the year ended December 31, 2012 was $2 million (2011 - $2 million, 2010 - $2 million).

9. INTANGIBLE ASSETS

December 31, 2012	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**20.6%**	**128**	**37**	**91**
CIS	**10.0%**	**127**	**41**	**86**
		255	**78**	**177**

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	20.0%	111	40	71
CIS	10.1%	127	28	99
		238	68	170

Intangible assets include $33 million of work-in-progress as at December 31, 2012 (2011 - $21 million). Total amortization expense for intangible assets was $31 million for the year ended December 31, 2012 (2011 - $31 million, 2010 - $32 million). The Company expects aggregate amortization expense for the years ending December 31, 2013 through 2017 of $37 million, $33 million, $28 million, $23 million and $20 million, respectively.

10. ACCOUNTS PAYABLE AND OTHER

December 31,	**2012**	2011
(millions of Canadian dollars)		
Operating accrued liabilities	**281**	246
Security deposits	**67**	79
Budget billing plan payable	**59**	136
Trade payables	**59**	78
Dividends payable	**51**	56
Regulatory liabilities *(Note 4)*	**39**	32
Taxes payable	**28**	26
Interest payable	**26**	26
Due to affiliates *(Note 20)*	**8**	10
Payroll payable	**8**	6
Current portion of OPEB liability *(Note 18)*	**5**	4
Current deferred income taxes *(Note 17)*	**-**	2
Other	**17**	17
	648	718

11. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2012**	2011
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium term notes	5.51%	2014-2050	**2,295**	2,295
Commercial paper and credit facility draws, net			**590**	555
Other			**13**	8
Total debt			**2,983**	2,943
Short-term borrowings	1.10%		**(596)**	(556)
Long-term debt			**2,387**	2,387
Loans from affiliate company			**375**	375

For the years ending December 31, 2013 through 2017, medium-term note maturities are nil, $400 million, nil, nil, and $200 million respectively. The Company's debentures and medium term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2013 through 2017 are $135 million, $129 million, $113 million, $113 million, and $113 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Debentures and medium-term notes	**139**	140	149
Loans from affiliate company *(Note 20)*	**27**	27	27
Commercial paper and credit facility draws	**2**	3	2
Other interest and finance costs	**8**	8	11
Capitalized	**(6)**	(6)	(3)
	170	172	186

In 2012, total interest paid to third parties was $142 million (2011 - $149 million, 2010 - $158 million) and total interest paid to affiliate company was $34 million (2011 - $20 million, 2010 - $27 million).

CREDIT FACILITIES

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 maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option.

December 31, 2012	Maturity Dates	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc.	2014	**700**	**580**	**120**
St. Lawrence Gas Company, Inc.	2014	**12**	**10**	**2**
Total credit facilities		**712**	**590**	**122**

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

Credit facilities carried a weighted average standby fee of 0.22% per annum from January to August 2012 and 0.20% per annum from September to December 2012 on the unused portion and draws bear interest at market rates.

The Company's borrowings, whether debentures or medium-term notes, are unsecured. When issuing any new indebtedness with a maturity over 18 months, covenants contained in the Company's trust indenture require the pro forma long-term debt interest coverage ratio be at least 2.0 times for 12 consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as U.S. GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of financing costs and intercompany interest expense less gains on asset dispositions divided by the annual interest requirement. 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, 2012, the Company was in compliance with this covenant.

12. OTHER LONG-TERM LIABILITIES

December 31,	**2012**	2011
(millions of Canadian dollars)		
Regulatory liabilities *(Note 4)*	**867**	816
Pension and OPEB liabilities *(Note 18)*	**226**	203
Other	**1**	-
	1,094	1,019

13. 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 preference shares.

COMMON SHARES

	2012		2011		2010	
December 31,	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**142.3**	**1,137**	140.7	1,071	140.7	1,071
Common shares issued	**-**	**-**	1.6	66	-	-
Balance at end of year	**142.3**	**1,137**	142.3	1,137	140.7	1,071

PREFERENCE SHARES

December 31, 2012, 2011, and 2010	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 1	0.2	-	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

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

14. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis.

STOCK SPLIT

Effective May 25, 2011, a two-for-one split of the common shares of Enbridge was completed. All references to the outstanding option information have been retroactively restated to reflect the impact of the stock split.

INCENTIVE STOCK OPTIONS

Key employees of the Company 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.

December 31, 2012	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,568**	**20.84**		
Options granted	**480**	**38.34**		
Options exercised[1]	**(521)**	**17.35**		
Options outstanding at end of year	**2,527**	**24.88**	**6.3**	**37**
Options vested at end of year[2]	**1,305**	**19.38**	**4.6**	**26**

1 *The total intrinsic value of ISOs exercised during the year ended December 31, 2012 was $11 million (2011 - $8 million; 2010 - $4 million) and cash received by Enbridge on exercise was $6 million (2011 - $7 million; 2010 - $6 million).*

2 *The total fair value of options vested under the ISO Plan during the year ended December 31, 2012 was $2 million (2011 - $1 million; 2010 - $1 million).*

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2012**	2011	2010
Fair value per option *(Canadian dollars)*[1]	**4.81**	4.19	3.44
Valuation assumptions			
Expected option term *(years)*[2]	**5**	6	6
Expected volatility[3]	**19.7%**	18.6%	19.7%
Expected dividend yield[4]	**3.0%**	3.4%	3.6%
Risk-free interest rate[5]	**1.3%**	2.9%	2.7%

1 *Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $4.65 (2011 - $4.01; 2010 - $3.28) for Canadian employees and US$5.58 (2011 - US$5.11, 2010 - US$4.00) for United States employees.*

2 *The expected option term is based on historical exercise practice.*

3 *Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.*

4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*

5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.*

Compensation expense recorded for the year ended December 31, 2012 for ISOs was $3 million (2011 - $3 million, 2010 - $2 million). At December 31, 2012, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $3 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted by Enbridge to executive officers of the Company and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on August 15, 2012 under the 2007 plan. Time vesting requirements for the 2012 grant are fulfilled evenly over a five-year term, ending August 15, 2017. The 2012 grant's performance targets are based on Enbridge's share price and must be met by February 15, 2019 or the options expire. If targets are met by February 15, 2019, the options are exercisable until August 15, 2020.

December 31, 2012	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**-**	**-**		
Options granted	**169**	**39.34**		
Options outstanding at end of year	**169**	**39.34**	**7.6**	**8**

Weighted average assumptions used to determine the fair value of the PBSOs using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	**2012**
Fair value per option *(Canadian dollars)*	**4.25**
Valuation assumptions	
Expected option term *(years)*[1]	**8**
Expected volatility[2]	**16.1%**
Expected dividend yield[3]	**2.8%**
Risk-free interest rate[4]	**1.6%**

1 *The expected option term is based on historical exercise practice.*
2 *Expected volatility is determined with reference to historic daily share price volatility.*
3 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*
4 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields.*

Compensation expense for PBSOs was nil for the years ended December 31, 2012, 2011 and 2010. At December 31, 2012, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PBSO Plan was $1 million. The cost is expected to be fully recognized over a weighted average period of approximately five years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company 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 for 20 days prior to the maturity of the grant 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 2010, 2011 and 2012 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 earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2012 expense, multipliers of two, based upon multiplier estimates at December 31, 2012, were used for each of the 2010, 2011 and 2012 PSU grants.

December 31, 2012	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**37**		
Units granted	**16**		
Units matured[1]	**(19)**		
Dividend reinvestment	**2**		
Units outstanding at end of year	**36**	**1.5**	**3**

1 *The total amount paid by Enbridge during the year ended December 31, 2012 for PSUs was $1 million (2011 - $1 million; 2010 - nil).*

Compensation expense recorded for the year ended December 31, 2012 for PSUs was $7 million (2011 - $6 million; 2010 - $4 million). As of December 31, 2012, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $2 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a 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 for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2012	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**254**		
Units granted	**103**		
Units cancelled	**(7)**		
Units matured[1]	**(132)**		
Dividend reinvestment	**10**		
Units outstanding at end of year	**228**	**1.4**	**10**

1 *The total amount paid by Enbridge during the year ended December 31, 2012 for RSUs was $5 million (2011 - $5 million; 2010 - $3 million).*

Compensation expense recorded for the year ended December 31, 2012 for RSUs was $5 million (2011 - $5 million; 2010 - $5 million). As of December 31, 2012, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $5 million and is expected to be fully recognized over a weighted average period of less than two years.

15. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

	Cash Flow Hedges	Cumulative Translation Adjustment	OPEB Actuarial Loss Adjustment	Total
(millions of Canadian dollars)				
Balance at January 1, 2010	3	(5)	6	4
Changes during the year	(14)	(1)	(4)	(19)
Tax impact	(1)	-	1	-
	(15)	(1)	(3)	(19)
Balance at December 31, 2010	(12)	(6)	3	(15)
Changes during the year	1	-	(13)	(12)
Tax impact	-	-	3	3
	1	-	(10)	(9)
Balance at December 31, 2011	(11)	(6)	(7)	(24)
Changes during the year	**1**	**-**	**(4)**	**(3)**
Tax impact	**-**	**-**	**1**	**1**
	1	**-**	**(3)**	**(2)**
Balance at December 31, 2012	**(10)**	**(6)**	**(10)**	**(26)**

16. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

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. The Company uses qualifying derivative instruments to manage some of the risks noted below.

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, primarily commercial paper. Floating to fixed interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense on variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances.

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 (2011 - 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. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil (2011 - nil).

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the location on the Consolidated Statements of Financial Position and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges or net investment hedges at December 31, 2012 or 2011.

December 31,	**2012**	2011
(millions of Canadian dollars)		
Deferred amounts and other assets		
Interest rate contracts	**1**	-
Accounts payable and other		
Interest rate contracts	**(1)**	(1)
Other long-term liabilities		
Interest rate contracts	**(1)**	-
Total net derivative liability		
Interest rate contracts	**(1)**	(1)

1 As presented in the Consolidated Statements of Financial Position.

The Company's derivatives instruments mature through 2017 and have a notional principal of $673 million for interest rate contracts for short-term borrowings (2011 - $111 million), and $1,007 million for interest rate contracts on long-term debt (2011 - nil).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Amount of unrealized loss recognized in OCI			
Cash flow hedges			
Interest rate contracts	**(1)**	(2)	(25)
	(1)	(2)	(25)
Amount of loss reclassified from accumulated other comprehensive loss to earnings *(effective portion)*			
Interest rate contracts[1]	**2**	3	3
	2	3	3

1 Loss reported within Interest expense in the Consolidated Statements of Earnings.

The Company estimates that no AOCI 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. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 60 months at December 31, 2012.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 20 and 21)* as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 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 and 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 securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. As at December 31, 2012, the Company had filed a preliminary shelf prospectus, and the final prospectus was filed in January 2013 *(Note 22)*. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 11)* with a diversified group of banks and institutions which, if necessary, enables 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, 2012. 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.

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 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 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 related to the base year of the IR plan (2007) and were escalated by the approved formula during the IR term.

Entering into derivative financial instruments may also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily 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.

The Company generally has a policy of entering into individual International Securities Dealers Association (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with those specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

At December 31, 2012, the Company had a maximum exposure to credit risk of $1 million (2011 - nil) related to its derivative counterparties.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair 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.

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. The Company does not have any derivative instruments classified as Level 1.

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 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. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2012, the Company had Level 2 derivative assets with fair value of $1 million (2011 - nil), and Level 2 derivative liabilities with fair value of $2 million (2011 - $1 million).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at December 31, 2012 or 2011.

Fair Value of Other Financial Instruments
The Company's investment in IPL System Inc., an affiliate company, is a preference share investment carried at a cost of $825 million at December 31, 2012 (2011 - $825 million), which approximates its fair value and redemption value.

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, and is classified as a Level 2 measurement. At December 31, 2012, the Company's long-term debt had a carrying value of $2,387 million (2011 - $2,387 million) and a fair value of $2,994 million (2011 - $2,943 million).

The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity.

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**291**	234	229
Combined statutory income tax rate	**26.5%**	28.3%	31.0%
Income taxes at statutory rate	**77**	66	71
Increase/(decrease) resulting from:			
Deferred income taxes related to regulated operations	**(13)**	-	7
Non-taxable dividend income from affiliate company	**(17)**	(18)	(19)
Tax rates and legislated tax changes	**8**	-	-
Intercompany sale of investment[1]	**5**	-	-
Other	**1**	(5)	(6)
Income taxes before discontinued operations	**61**	43	53
Effective income tax rate	**20.9%**	18.3%	23.0%

1 *In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund. As the transaction occurred between entities under common control of Enbridge, the intercompany gain realized as a result of this transfer has been eliminated, although cash income taxes of $5 million remain as a charge to earnings.*

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2012**	2011
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(317)**	(290)
Investments	**-**	(6)
Reserves	**(23)**	-
Regulatory assets	**(52)**	(41)
Other	**-**	(2)
Total deferred income tax liabilities	**(392)**	(339)
Deferred income tax assets		
Financial derivatives	**4**	4
Retirement and postretirement benefits	**23**	23
Other	**8**	-
Total deferred income tax assets	**35**	27
Net deferred income tax liabilities	**(357)**	(312)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 6)*	**5**	-
Total deferred income tax assets	**5**	-
Liabilities		
Deferred income taxes	**(362)**	(304)
Accounts payable and other *(Note 10)*	**-**	(2)
Liabilities associated with discontinued operations	**-**	(6)
Total deferred income tax liabilities	**(362)**	(312)
Net deferred income tax liabilities	**(357)**	(312)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2012.

The Company and its subsidiaries are subject to taxation in Canada. The Company is open to examination by certain tax authorities for the 2008 to 2012 tax years. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario).

18. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company maintains a non-contributory basic pension plan that provides either defined benefit 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.

A measurement date of December 31, 2012 was used to determine the plan assets and accrued benefit obligation for the pension plans.

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 date of the most recently filed actuarial valuation was December 31, 2009. The effective date of the next required actuarial valuation is December 31, 2012.

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.

OTHER POSTRETIREMENT BENEFITS

OPEB primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS

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 plans using the accrual method.

	Pension		OPEB	
December 31,	**2012**	2011	**2012**	2011
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**852**	702	**103**	87
Service cost	**21**	16	**2**	1
Interest cost	**37**	39	**4**	5
Actuarial loss	**33**	127	**5**	13
Benefits paid	**(37)**	(33)	**(3)**	(3)
Other	**(1)**	1	**1**	-
Benefit obligation at end of year	**905**	852	**112**	103
Change in plan assets				
Fair value of plan assets at beginning of year	**744**	759	**6**	4
Transfer to the defined contribution component	**-**	(1)	**-**	-
Actual return on plan assets	**59**	15	**1**	-
Employer's contributions	**17**	4	**4**	6
Benefits paid	**(37)**	(33)	**(3)**	(3)
Other	**(1)**	-	**(1)**	(1)
Fair value of plan assets at end of year	**782**	744	**7**	6
Underfunded status at end of year	**(123)**	(108)	**(105)**	(97)
Presented as follows:				
Deferred amounts and other assets *(Note 8)*	**3**	2	**-**	-
Accounts payable and other *(Note 10)*	**-**	-	**(5)**	(4)
Other long-term liabilities *(Note 12)*	**(126)**	(110)	**(100)**	(93)

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

	Pension			OPEB		
Year ended December 31,	**2012**	2011	2010	**2012**	2011	2010
Discount rate	**4.3%**	4.5%	5.7%	**4.3%**	4.5%	5.7%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**3.5%**	5.0%	5.0%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2012**	2011	2010	**2012**	2011	2010
(millions of Canadian dollars)						
Benefits earned during the year	**21**	16	12	**2**	1	1
Interest cost on projected benefit obligations	**37**	39	39	**4**	5	5
Actual return on plan assets	**(59)**	(15)	(78)	**(1)**	-	-
Actuarial loss	**33**	127	79	**5**	13	5
Difference between actual and expected return on plan assets						
Return on plan assets	**10**	(38)	29	**-**	-	-
Amortization of prior service costs	**1**	2	1	**-**	-	-
Amortization of actuarial loss	**(3)**	(110)	(64)	**(4)**	(13)	(5)
Net defined benefit costs on an accrual basis	**40**	21	18	**6**	6	6
Defined contribution benefit costs	**1**	1	2	**-**	-	-
Net benefit cost recognized on an accrual basis	**41**	22	20	**6**	6	6
Net amount recognized in OCI						
Net actuarial loss[1]	**-**	-	-	**4**	13	4
Total amount recognized in OCI	**-**	-	-	**4**	13	4
Total net benefit cost on an accrual basis and amount recognized in OCI	**41**	22	20	**10**	19	10

1 *Unamortized actuarial losses included in AOCI, before tax, were $14 million relating to OPEB at December 31, 2012 (2011 - $10 million loss, 2010 - $3 million gain).*

The Company estimates that approximately $29 million related to pension plans and OPEB at December 31, 2012 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Prior service costs	**1**	**-**	**1**
Actuarial Loss	**28**	**-**	**28**
	29	**-**	**29**

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for rate-making purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers in future rates *(Note 4)*.

Pension costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension costs due to the regulatory mechanism in place. As a result, the net pension expense primarily consisted of contributions to the pension plan. Such costs totaled $18 million for pension benefits for the year ended December 31, 2012 (2011 – $4 million, 2010 – $4 million).

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

	Pension			OPEB		
Year ended December 31,	**2012**	2011	2010	**2012**	2011	2010
Discount rate	**4.5%**	5.7%	6.6%	**4.5%**	5.7%	6.6%
Average rate of return on pension plan assets	**7.0%**	7.3%	7.1%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**5.0%**	5.0%	5.0%

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	8.2%	4.5%	2029
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $13 million in the accumulated postretirement 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 postretirement benefit obligations and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of the liabilities of the plans; (ii) the investment horizon of the plans; (iii) the going concern and solvency funded status and cash flow requirements of the plans; (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.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2012**	2011	**2012**	2011
Expected rate of return	**7.0%**	7.3%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2012, the pension assets were invested in 60% (2011 – 55%) in equity securities, 37% (2011 – 44%) in fixed income securities and 3% (2011 – 1%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $8 million (2011 - $19 million) have been excluded from the table below.

	2012				2011			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**18**	**-**	**-**	**18**	4	-	-	4
Fixed income securities								
Canadian government real return bonds	**57**	**-**	**-**	**57**	82	-	-	82
Canadian corporate bond index fund	**109**	**5**	**-**	**114**	237	-	-	237
Canadian government bond index fund	**109**	**-**	**-**	**109**	-	-	-	-
United States bond index fund	**-**	**2**	**-**	**2**	-	-	-	-
Equity								
Canadian equity securities	**113**	**-**	**-**	**113**	90	-	-	90
Canadian equity funds	**4**	**59**	**-**	**63**	47	-	-	47
United States equity funds	**58**	**13**	**-**	**71**	-	-	-	-
Global equity funds	**100**	**74**	**-**	**174**	221	-	-	221
Private equity investment[4]	**-**	**-**	**38**	**38**	-	-	44	44
Real estate[5]	**-**	**-**	**15**	**15**	-	-	-	-
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	-	-	-	-
Fixed income securities								
United States municipal bonds	**2**	**-**	**-**	**2**	-	-	-	-
Global bond fund	**-**	**-**	**-**	**-**	-	3	-	3
Equity								
United States equity fund	**2**	**2**	**-**	**4**	-	-	-	-
Global equity fund	**-**	**-**	**-**	**-**	-	3	-	3

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in Global Infrastructure Limited Partnership is established through the use of valuation models.
5 The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd is established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2012**	2011
Balance at beginning of year	**44**	42
Unrealized and realized gains	**7**	6
Purchases and settlements, net	**2**	(4)
Balance at end of year	**53**	44

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2012**	2011	**2012**	2011
(millions of Canadian dollars)				
Total contributions	**18**	4	**4**	6
Contributions expected to be paid in 2013	**45**		**5**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2013	2014	2015	2016	2017	2018-2022
(millions of Canadian dollars)						
Expected future benefit payments	41	44	47	49	51	290

19. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Accounts receivable and other	**74**	139	8
Gas inventories	**54**	20	(4)
Accounts payable and other	**(51)**	(144)	41
	77	15	45

SIGNIFICANT NON-CASH ITEMS
In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares.

20. RELATED PARTY TRANSACTIONS

All related party transactions, other than those disclosed under Other Transactions, are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
IPL System Inc.			
Dividend income	**63**	63	63
Interest expense	**27**	27	27
Enbridge			
Purchase of treasury and other management services	**39**	34	32
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**25**	28	30
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**24**	24	27
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	2	1
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**25**	25	25
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**18**	18	17
Enbridge Commercial Services Inc.			
Purchase of information services	**-**	-	2

The Company had related party balances as follows:

December 31,	**2012**	2011
(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**	9
Note payable to affiliate company		
Enbridge (U.S.)	**13**	8
Other accounts receivables/(payables)		
Enbridge	**(7)**	(1)
Gazifère Inc.	**4**	4
Enbridge Pipelines Inc.	**3**	1
Niagara Gas Transmission Ltd.	**-**	2

Financing Transactions

The Company has invested in Class D, non-voting, redeemable, retractable preference shares of IPL System Inc., an affiliate under common control. At December 31, 2012, the investment of $825 million (2011 - $825 million) in these shares resulted in a weighted average dividend yield of 7.60%.

At December 31, 2012, 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 preference shares of the Company. For the year ended December 31, 2012, interest paid amounted to $34 million (2011 - $20 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 on a cost recovery basis.

Wholesale Service

These gas procurement and transportation 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 2013 – $69 million, 2014 to 2015 – $120 million, and nil thereafter.

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.

Other Transactions
In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund, an affiliated entity under common control, for cash proceeds of $72 million *(Note 5)*.

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares *(Note 5)*.

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

21. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $1,183 million which are expected to be paid within the next five years and $149 million in total for years thereafter.

Minimum future payments under operating leases are estimated at $12 million in aggregate. Estimated annual lease payments for the years ended December 31, 2013 through 2017 are $3 million, $3 million, $3 million, $3 million and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, were $3 million, $3 million, and $2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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 2013 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.

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.

22. SUBSEQUENT EVENT

An $800 million shelf prospectus filed in November 2010 expired during the fourth quarter of 2012. A new $800 million shelf prospectus was filed in January 2013 and will be effective for a 25 month period.

CORPORATE INFORMATION

TRUSTEE AND REGISTRARS

Debenture
9.85% debenture

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6
and in Montreal, Calgary and Vancouver

For the above debenture, CIBC Mellon Trust Company of Canada is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

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

TRUSTEE

Medium Term Notes
CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

Group 3 Preference Shares
Computershare Investor Services Inc.
100 University Avenue, 8th Floor
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, and 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 *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 2, 2012), which is incorporated herein by reference.

ENBRIDGE GAS DISTRIBUTION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2012

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 14, 2013 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) as at and for the year ended December 31, 2012, which are prepared in accordance with United States generally accepted accounting principles (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements prepared in accordance with Part V – Pre-changeover accounting standards of the Canadian Institute of Chartered Accountants Handbook (Canadian GAAP) and MD&A contained in the Company's Annual Report for the year ended December 31, 2011. In addition, annual consolidated financial statements for the years ended December 31, 2011 and 2010 were prepared in accordance with U.S. GAAP and were filed with Canadian securities regulators on a voluntary basis. Comparative figures contained in this MD&A have been restated in accordance with U.S. GAAP. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. 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 over 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. (Enbridge).

The Company also owns and operates unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

PERFORMANCE OVERVIEW

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to the common shareholder[1]	**232**	191	174
Earnings excluding the effect of weather[2]	**255**	190	186
Cash flow data			
Cash provided by operating activities[3]	**578**	509	512
Cash used by investing activities	**(414)**	(461)	(365)
Cash used by financing activities	**(170)**	(52)	(154)
Dividends			
Common share dividends declared	**201**	220	215
Dividends declared per common share	**1.41**	1.56	1.53
Preference share dividends declared	**2**	2	2
Dividends declared per preference share	**0.60**	0.60	0.52
Total revenues			
Gas commodity and distribution revenues	**1,869**	1,880	1,781
Transportation of gas for customers	**345**	421	458
Other revenue[4]	**202**	103	110
	2,416	2,404	2,349
Total assets[5]	**7,889**	7,748	7,585
Total long-term liabilities[6]	**4,218**	4,091	3,880
Number of active customers[7] *(thousands)*	**2,032**	1,997	1,963
Heating degree days[8]			
Actual	**3,194**	3,597	3,466
Forecasted based on normal weather	**3,532**	3,602	3,546

1. *Includes earnings from discontinued operations of $4 million and $2 million for the years ended December 31, 2012 and 2011, respectively.*
2. *Earnings excluding the effect of weather is a non-GAAP measure that does not have any standardized meaning prescribed by U.S. GAAP. For more information on this non-GAAP measure see page 4.*
3. *Includes cash provided from discontinued operations of $12 million and $3 million for the years ended December 31, 2012 and 2011, respectively.*
4. *Excludes revenues from discontinued operations of $10 million and $3 million for the years ended December 31, 2012 and 2011, respectively.*
5. *Total assets at December 31, 2011 include $74 million of assets from discontinued operations.*
6. *Total long-term liabilities as at December 31, 2011 include $6 million of liabilities from discontinued operations.*
7. *Number of active customers is the number of natural gas consuming customers at the end of the year.*
8. *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 distribution 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 Greater Toronto Area.*

EARNINGS ATTRIBUTABLE TO THE COMMON SHAREHOLDER

Earnings attributable to the common shareholder were $232 million for the year ended December 31, 2012 compared with $191 million for the year ended December 31, 2011. The increase was primarily due to the recognition of a regulatory asset related to other postretirement benefits (OPEB), higher revenue related to pipeline optimization activities and customer growth. This was partially offset by warmer weather, higher income taxes, and higher depreciation and amortization expense.

Earnings attributable to the common shareholder were $191 million for the year ended December 31, 2011 compared with $174 million for the year ended December 31, 2010. The increase was primarily due to colder weather, lower interest expense, lower income taxes, lower earnings sharing, customer growth and higher distribution charges. This was partially offset by higher operating and administrative expenses and higher depreciation and amortization expense.

EARNINGS EXCLUDING THE EFFECT OF WEATHER

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Earnings attributable to the common shareholder	**232**	191	174
Warmer/(colder) than normal weather	**23**	(1)	12
Earnings excluding the effect of weather	**255**	190	186

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 measure enables a meaningful analysis of the operational performance of the Company over different periods.

Normal weather is the weather forecast by the Company in its distribution franchise area, 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 $255 million for the year ended December 31, 2012 compared with $190 million for the year ended December 31, 2011. The increase was primarily due to the recognition of a regulatory asset related to OPEB, higher revenue related to pipeline optimization activities and customer growth. This was partially offset by higher income taxes, and higher depreciation and amortization expense.

Earnings excluding the effect of weather were $190 million for the year ended December 31, 2011 compared with $186 million for the year ended December 31, 2010. The increase was primarily due to lower interest expense, lower income taxes, lower earnings sharing and customer growth. This was partially offset by higher operating and administrative expenses and higher depreciation and amortization expense.

REVENUES

Total revenues for the year ended December 31, 2012 were $2,416 million compared with $2,404 million for the year ended December 31, 2011. The increase in total revenues was primarily due to the recognition of an OPEB regulatory asset, higher revenue related to pipeline optimization activities and customer growth, partially offset by warmer weather and lower natural gas prices.

Total revenues for the year ended December 31, 2011 were $2,404 million compared with $2,349 million for the year ended December 31, 2010. The increase in total revenues was primarily a result of colder weather, customer growth, and higher distribution charges, partially offset by lower natural gas prices and other revenue.

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; 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 underlie 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 attributable 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 U.S. GAAP and is not considered a U.S. 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. The Company will target new growth opportunities, which complement its core business, by pursuing newly evolving business models and technologies. In addition, the Company will continue to grow its natural gas storage assets.

Operations safety and system integrity continues to be the Company's number one priority and sets the foundation for the Company's strategic plan. Core to this priority is the focus on system integrity, and environmental and safety programs, which charts the course for best-in-class practices.

RECENT DEVELOPMENTS

2013 COST OF SERVICE RATE APPLICATION

In January 2012, the Company filed an application with the OEB to set rates for 2013 on a Cost of Service basis. The Company applied for distribution revenue of $1,104 million. The Company also applied to utilize U.S. GAAP for regulatory filing purposes. The OEB issued a preliminary decision in May 2012, approving the use of U.S. GAAP for regulatory purposes. In October 2012, the Company filed a settlement agreement reached with its interveners with the OEB relating to the Company's 2013 rate application. The settlement agreement was approved by the OEB in November 2012, which resolved all elements of the rate application except a requested increase in the deemed equity level which was heard by the OEB in November 2012. In its final decision issued on February 7, 2013, the OEB denied the Company's requested increase in the deemed equity level. The OEB concluded that a test of an increase in business or financial risk must be met before any review of a required change in deemed equity level would be considered and that the Company's risk had not increased since the last time its deemed equity level was determined.

The settlement agreement approved in November 2012 also established the right to recover OPEB costs of $89 million. The amount will be collected in rates on a straight-line basis over a 20-year period commencing in 2013. The rate order further provided for future OPEB and pension costs, determined on an accrual basis, to be recovered in rates in 2013.

GREATER TORONTO AREA (GTA) PROJECT

In September 2012, the Company announced plans to expand its natural gas distribution system in the GTA to meet the demands of growth and continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of approximately $600 million, the proposed GTA Project will consist of two segments of pipeline and related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. The Company filed a leave to construct application with the OEB in December 2012. Subject to OEB approval, construction is targeted to start in 2014, with an expected completion date in 2015.

FRANKLIN COUNTY EXPANSION PROJECT

In July 2012, St. Lawrence received regulatory approval to expand its operations to Franklin County in New York State. The construction associated with the expansion began in August 2012 and the completion of the high pressure distribution line is slated for the fall of 2013. The total capital cost over five years, including several distribution systems, is estimated to be $41 million, with expenditures to date of approximately $14 million. The expansion is expected to add 4,400 potential customers to St. Lawrence's distribution system, which had 15,700 customers at December 31, 2012.

DISPOSITION OF AMHERSTBURG SOLAR PROJECTS

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund (the Fund), an affiliated entity under common control, for proceeds of $72 million. Project Amherstburg consisted primarily of property, plant and equipment and intangible assets. The excess of the sale price over the net book value at the time of disposition of $17 million inclusive of deferred income tax recoveries of $10 million were recognized as additional paid-in capital for the year ended December 31, 2012. No gain or loss was recognized in earnings on the disposition; however, $5 million of cash income taxes incurred on the related capital gains remains as a charge to consolidated earnings for the year ended December 31, 2012.

TWO MILLION CUSTOMERS

During the fourth quarter of 2012, the Company reached the milestone of connecting its two millionth customer.

RESULTS OF OPERATIONS

Year ended December 31,	2012	2011	2010
(millions of Canadian dollars)			
Gas distribution margin	**1,015**	1,033	1,003
Other revenue	**202**	103	110
Operating and administrative expenses	**(449)**	(437)	(406)
Depreciation and amortization	**(320)**	(302)	(292)
Municipal and other taxes	**(40)**	(41)	(44)
Earnings sharing	**(10)**	(13)	(19)
Affiliate financing income	**63**	63	63
Interest expense	**(170)**	(172)	(186)
Income taxes	**(61)**	(43)	(53)
Earnings from continuing operations	**230**	191	176
Earnings from discontinued operations, net of tax	**4**	2	-
Earnings	**234**	193	176
Earnings attributable to the common shareholder	**232**	191	174

GAS DISTRIBUTION MARGIN

Gas distribution margin for the year ended December 31, 2012 decreased by $18 million compared with the year ended December 31, 2011. The decrease was primarily due to warmer weather, partially offset by customer growth and higher distribution charges.

The heating degree days reported in 2012 were 338 heating degree days warmer compared with forecast heating degree days. On a weather-normalized basis, net gas distribution margin for the year ended December 31, 2012 would have been higher by $31 million (2011 - lower by $1 million). As experienced in 2011, there was significant variability in the 2012 heating degree day profiles of the geographical regions in which the Company operates. Weather, measured in heating degree days, was 3,194 heating degree days for the year ended December 31, 2012 compared with 3,597 heating degree days for the year ended December 31, 2011.

Gas distribution margin for the year ended December 31, 2011 increased by $30 million compared with the year ended December 31, 2010. The increase was primarily due to colder weather, customer growth and higher distribution charges.

The heating degree days reported in 2011 were 5 heating degree days warmer compared with forecast heating degree days. However, due to the relative effectiveness and monthly distribution of heating degree days in the year, on a weather-normalized basis, net gas distribution margin for the year ended December 31, 2011 would have been lower by $1 million (2010 - higher by $17 million). As experienced in 2010, there was significant variability in the 2011 heating degree day profiles of the geographical regions in which the Company operates. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude. Weather, measured in heating degree days, was 3,597 heating degree days for the year ended December 31, 2011 compared with 3,466 heating degree days for the year ended December 31, 2010.

OTHER REVENUE

Other revenue for the year ended December 31, 2012 increased by $99 million compared with the year ended December 31, 2011. The increase was primarily due to the recognition of a $89 million regulatory asset related to OPEB and higher revenue related to pipeline optimization activities and unregulated storage operations. The recognition of the OPEB regulatory asset and the corresponding increase to Other revenue resulted from a November 2012 rate order which established the right to recover OPEB costs of $89 million on a straight-line basis over a 20-year period, commencing in 2013.

Other revenue for the year ended December 31, 2011 decreased by $7 million compared with the year ended December 31, 2010. The decrease was primarily due to higher Shared Savings Mechanism revenue in the prior year which resulted from exceeding targets on delivery of energy efficiency programs for promotion of energy efficient use of natural gas to customers. Contributing to the decrease was lower revenue from the management of fee-for-service energy efficiency initiatives. This was partially offset by higher unregulated storage revenue.

OPERATING AND ADMINISTRATIVE

Operating and administrative expenses for the year ended December 31, 2012 increased by $12 million compared with the year ended December 31, 2011. The increase was primarily due to higher employee related costs, and higher operational, pipeline integrity and safety costs. This was partially offset by lower amortization of regulatory assets and lower customer support related costs.

Operating and administrative expenses for the year ended December 31, 2011 increased by $31 million compared with the year ended December 31, 2010. The increase was primarily due to higher employee related costs, higher pipeline integrity and safety costs, and higher customer support related costs.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization charge for the year ended December 31, 2012 increased by $18 million compared with the year ended December 31, 2011. Depreciation and amortization charge for the year ended December 31, 2011 increased by $10 million compared with the year ended December 31, 2010. The increases in depreciation and amortization in both years were primarily due to higher overall asset bases resulting from customer growth projects and improvements to the distribution system.

MUNICIPAL AND OTHER TAXES

Municipal and other taxes were relatively consistent for the year ended December 31, 2012 compared with the year ended December 31, 2011.

Municipal and other taxes for the year ended December 31, 2011 decreased by $3 million compared with the year ended December 31, 2010. The decrease was primarily due to the elimination of Ontario's capital tax in 2010.

EARNINGS SHARING

Earnings sharing represents the estimated customer portion of regulated earnings in excess of 100 basis points above the allowed utility return on equity (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 resulted in the return of revenue of $10 million to customers for the year ended December 31, 2012 (2011 - $13 million, 2010 - $19 million), subject to OEB approval. Earnings sharing for 2012 was $3 million lower compared to 2011 primarily due to lower regulated earnings. Earnings sharing for 2011 was $6 million lower compared to 2010 primarily due to a higher rate base threshold in 2011.

INTEREST EXPENSE

Interest expense for the year ended December 31, 2012 decreased by $2 million compared with the year ended December 31, 2011. The decrease was primarily due to a lower interest rate on a portion of replaced long-term debt and lower commitment fees on the credit facility.

Interest expense for the year ended December 31, 2011 decreased by $14 million compared with the year ended December 31, 2010. The decrease was primarily due to the Company's redemption of its $150 million 10.80% debentures in April 2011, which were replaced with the issuance of $100 million medium term notes (MTNs) at 4.95% and additional draws on its credit facilities at lower interest rates.

INCOME TAXES

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**291**	234	229
Income taxes	**61**	43	53
Effective tax rate (%)	**20.9**	18.3	23.0

The effective tax rate for the year ended December 31, 2012 was higher compared with the year ended December 31, 2011. The increase was due to a 1.5% increase in the Ontario income tax rate and a capital gain from the sale of Project Amherstburg, partially offset by temporary differences relating to property, plant and equipment and intangible assets.

The effective tax rate for the year ended December 31, 2011 was lower compared with the year ended December 31, 2010. The decrease was due to temporary differences relating to property, plant and equipment and intangible assets, and an approximate 2.75% reduction in the combined federal and Ontario income tax rates.

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).

Rates for 2013 have been set on a Cost of Service basis pursuant to a settlement agreement approved by the OEB in November 2012. See *Recent Developments – 2013 Cost of Service Rate Application*.

INCENTIVE REGULATION

In 2008, pursuant to OEB approval, the Company moved to an incentive regulation (IR) methodology calculated on a revenue per customer basis, which remained in effect through 2012. The objectives of the IR Settlement were as follows:

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

2012 IR RATE ADJUSTMENT APPLICATION

In September 2011, the Company filed an application with the OEB to adjust rates for 2012 pursuant to the Company’s approved IR formula. The application was in accordance with the Company’s historical basis of accounting. The Company applied for distribution revenue of $1,024 million, of which $1,004 million or 98% was approved on an interim basis for recovery by the OEB. The rate adjustment was effective January 1, 2012. An OEB hearing with respect to the remaining $20 million distribution revenue and related issues was held in January 2012. In May 2012, the OEB issued a decision rejecting the requested treatment and recovery of the elements which made up the remaining $20 million distribution revenue.

IMPACT OF RATE REGULATION

The Company follows U.S. 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 Standards Codification 980 (ASC 980), *Regulated Operations*, 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 4 to the 2012 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. Future removal and site restoration reserves, 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 approved 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 and the issuance of replacement debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay dividends.

An $800 million shelf prospectus filed in November 2010 expired during the fourth quarter of 2012. A new $800 million shelf prospectus was filed in January 2013 and will be effective for a 25 month period.

In August 2012, the Company extended the term out date of its $700 million committed line of credit for an additional year to August 2013, with a maturity date in August 2014.

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 2011, the Company issued an additional $100 million of MTNs under the same terms as the $200 million 40 year MTN pricing supplement issued in 2010 at an interest rate of 4.95%. In 2012, the Company had total debenture maturities of nil (2011 - $150 million).

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, 2012.

	Maturity Dates	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc.	**2014**	**700**	**580**	**120**
St. Lawrence Gas Company, Inc.	**2014**	**12**	**10**	**2**
Total credit facilities		**712**	**590**	**122**

1. *Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.*

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,	**2012**	2011
(millions of Canadian dollars)		
Cash and cash equivalents[1]	**3**	6
Accounts receivable and other[2]	**594**	659
Gas inventories	**326**	380
Bank overdraft	**(5)**	(7)
Short-term borrowings	**(596)**	(556)
Accounts payable and other	**(648)**	(718)
Working capital	**(326)**	(236)

1. *Excludes Cash and cash equivalents from discontinued operations of $3 million at December 31, 2011.*
2. *Excludes Accounts receivable and other from discontinued operations of $4 million at December 31, 2011.*

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, 2012, this ratio was 2.26 (2011 - 2.47). 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.

OPERATING ACTIVITIES

Cash provided by operating activities was $578 million for the year ended December 31, 2012 compared with $509 million in 2011. The increase primarily resulted from higher declines in natural gas prices and a decrease in the net settlement on purchase gas variances owing to customers compared to the prior year.

Cash provided by operating activities was $509 million for the year ended December 31, 2011 compared with $512 million in 2010. The decrease was due to a higher net settlement on purchase gas variance owing to customers, partially offset by lower receivables from customers as a result of the impact of weather.

INVESTING ACTIVITIES

Cash used for investing activities was $414 million for the year ended December 31, 2012 compared with $461 million in 2011. The decrease in cash used was primarily due to cash proceeds from the sale of Project Amherstburg and the completion of construction of a technical training facility in the prior year. This was partially offset by higher comparative capital spending on improvements to the distribution system and customer growth projects.

Cash used for investing activities was $461 million for the year ended December 31, 2011 compared with $365 million in 2010. The increase was primarily due to higher comparative capital spending on unregulated natural gas storage projects, customer growth projects, improvements to the distribution system and construction of a technical training facility.

CAPITAL EXPENDITURES

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
System improvements and upgrades	**199**	159	160
System expansion	**157**	140	107
Computers and communication equipment	**43**	38	32
Unregulated storage	**1**	32	7
Solar assets (Project Amherstburg)	**-**	68	-
Other	**79**	106	59
Total capital expenditures	**479**	543	365

The Company's existing distribution network consists of approximately 36,000 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 $560 million in 2013 on capital projects and maintenance. Annual capital expenditures in recent years have averaged approximately $430 million.

Major 2013 capital projects include the GTA project, the Franklin County Expansion project and the Ottawa reinforcement project. The net available liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently approved capital projects and to provide flexibility for new investment opportunities.

FINANCING ACTIVITIES

Cash used for financing activities was $170 million for the year ended December 31, 2012 compared with $52 million in 2011. The increase was primarily due to lower borrowings and the absence of debt repayments in 2012, partially offset by lower dividend payments compared to the prior year.

Cash used for financing activities was $52 million for the year ended December 31, 2011 compared with $154 million in 2010. The decrease was primarily due to issuances of short-term borrowings and the issuance of $100 million MTNs, partially offset by the repayment of the portion of long-term debt that became due.

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

PREFERENCE SHARES

Floating adjustable cumulative cash dividends on the Group 3, Series D preference 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 preference 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 preference shares can be converted, at the holder's option, into Group 2, Series D preference 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 preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference 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
Preference Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible	4,000,000
Common shares	142,345,114

1. *Outstanding share data information is provided as at February 14, 2013.*

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the consolidated statements of financial position between December 31, 2011 and December 31, 2012.

Consolidated Statements of Financial Position Category	Increase/ (Decrease)	Explanation
(millions of Canadian dollars)		
Accounts receivable and other	(65)	Primarily due to lower natural gas prices and lower sales volumes as a result of warmer weather in December 2012.
Gas inventories	(54)	Primarily due to lower natural gas prices and lower volumes in storage.
Property, plant and equipment, net	196	Primarily due to capital additions relating to distribution system improvements and customer growth projects, partially offset by depreciation.
Deferred amounts and other assets	134	Primarily due to the recording of a regulatory asset for OPEB costs per an OEB rate order and an increase in deferred taxes related to regulated assets.
Assets associated with discontinued operations	(67)	Due to the disposition of Project Amherstburg in December 2012.
Accounts payable and other	(70)	Primarily due to a decrease in the amounts to be settled with customers.
Other long-term liabilities	75	Primarily due to increased future removal and site restoration reserves, and higher pension underfunded balances and OPEB liabilities.
Deferred income taxes	58	Primarily due to timing differences related to regulated assets, and taxes related to the regulatory recoverable for OPEB costs.

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, certain volumetric imbalances typically result whereby the Company either holds natural gas on behalf of transportation service customers or such customers have consumed more natural gas than the amount delivered to the Company. Specific defined parameters are in place and are monitored carefully to ensure that the volume of such imbalances does not exceed certain threshold levels. Customer accounts beyond these defined threshold levels incur penalties. All volume imbalances are trued up annually. The Company also has strict credit policies in place to mitigate this risk.

Included in, or deducted from, physical 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, 2012, $65 million of natural gas was held on behalf of transportation service customers (December 31, 2011 - $100 million). These transactions have no impact on the Company's consolidated earnings 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 2013 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.

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]	2,387	-	400	200	1,787
Gas transportation and storage contracts	873	618	188	38	29
Loans from affiliate company[1]	375	-	-	-	375
Customer care service contracts[2]	302	57	119	126	-
Right-of-way commitments[3]	130	2	4	4	120
Capital commitments	27	19	4	4	-
Operating leases	12	3	6	3	-
Pension obligations[4]	45	45	-	-	-
Total contractual obligations	4,151	744	721	375	2,311

1. *Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*
2. *In 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. The OEB approved the Company's recovery of costs associated with the agreement in 2011.*
3. *Right-of-way payments are estimated to be approximately $2 million per year for the remaining life of all storage reservoirs, which has been assumed to be 60 years for purposes of calculating the amount of future minimum commitments beyond 2017.*
4. *Assumes only required payments will be made into the pension plans. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2012. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

QUARTERLY FINANCIAL INFORMATION[1]

2012	**Q1**	**Q2**	**Q3**	**Q4**	**Total**
(millions of Canadian dollars)					
Revenues[1,2]	**900**	**425**	**303**	**788**	**2,416**
Earnings attributable to the common shareholder[1,3]	**72**	**33**	**(2)**	**129**	**232**
Warmer/(colder) than normal weather	**24**	**-**	**-**	**(1)**	**23**

2011	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars)					
Revenues[1,2]	939	462	312	691	2,404
Earnings attributable to the common shareholder[1,3]	103	45	4	39	191
(Colder)/warmer than normal weather	(11)	(2)	-	12	(1)

1. *Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. GAAP. Comparative revenue amounts have been reclassified to conform with the current year's consolidated financial statement presentation.*
2. *Excludes revenues from discontinued operations of $1 million, $4 million, $4 million and $1 million for the three months ended March 31, 2012, June 30, 2012, September 30, 2012 and December 31, 2012, respectively (2011 – nil, nil, $2 million and $1 million, respectively).*
3. *Includes earnings from discontinued operations of nil, $2 million, $2 million and nil for the three months ended March 31, 2012, June 30, 2012, September 30, 2012 and December 31, 2012, respectively (2011 – nil, nil, $2 million and nil, respectively).*

Revenues include amounts billed to customers for natural gas, which vary 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 2012 HIGHLIGHTS

Earnings attributable to the common shareholder were $129 million for the three months ended December 31, 2012 compared with $39 million for the same period in 2011. The increase was primarily due to the recognition of an OPEB regulatory asset, lower operating and administrative expenses and colder weather. This was partially offset by higher income taxes and higher depreciation and amortization expense during the period.

Earnings applicable to the common shareholder were $39 million for the three months ended December 31, 2011 compared with $65 million for the same period in 2010. The decrease was primarily due to warmer weather, lower other revenue, higher operating and administrative expenses, and higher depreciation and amortization expense during the period. This was partially offset by lower income taxes and lower interest expense.

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 preference shares of IPL System Inc., an affiliated company under common control. At December 31, 2012, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2012, dividends received amounted to $63 million (2011 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2012 (2011 - $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 preference shares of the Company. For the year ended December 31, 2012, interest paid amounted to $27 million (2011 - $27 million) with an outstanding payable balance of $2 million at December 31, 2012 (2011 - $9 million).

Enbridge (U.S.), an affiliated company under common control, advanced St. Lawrence $13 million (2011 - $8 million) at the LIBOR rate plus 0.55%, payable on demand.

Enbridge, 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, 2012 were $39 million (2011 - $34 million) with an outstanding payable balance of $7 million at December 31, 2012 (2011 - $1 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, 2012 were $25 million (2011 - $28 million) with an outstanding receivable of $4 million at December 31, 2012 (2011 - $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, 2012 were $24 million (2011 - $24 million) with an outstanding payable of nil at December 31, 2012 (2011 - 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, 2012 were $2 million (2011 - $2 million) with an outstanding payable of nil at December 31, 2012 (2011 - 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, 2012 were $25 million (2011 - $25 million) with an outstanding payable of nil at December 31, 2012 (2011 - 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, 2012 were $18 million (2011 - $18 million) with an outstanding payable of nil at December 31, 2012 (2011 - nil).

Other Transactions
In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund, an affiliated entity under common control, for cash proceeds of $72 million.

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 Company's operations are regulated and are subject to regulatory risk. The Company retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize regulatory risk.

The formula approved by the OEB for determination of the ROE, which was embedded and escalated within rates over the 2008 to 2012 IR period, was based on the OEB's risk assessment of the Company for the 2007 fiscal year. See *Rate Regulation – Incentive Regulation*.

Under Cost of Service regulation in 2013, the OEB approves the ROE that the Company is allowed to earn, in addition to various other aspects of utility operations, through the regulatory process. The OEB approved ROE is based on the OEB's risk assessment of the Company. Rate relief may be sought for significant amounts that are not forecasted, allowing the Company to recover the costs of providing and maintaining the quality of its service, while achieving the allowed rate of return on rate base. To the extent the OEB denies recovery of any such costs, the Company is at risk.

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 and the price approved by the Regulators (including risk management costs for St. Lawrence). 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 IR agreement, the portion of fixed charges has increased 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 79% (2011 - 80%) 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 customers other than large volume transportation 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 (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. The Company uses qualifying derivative instruments to manage some of the risks noted below.

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, primarily commercial paper. Floating to fixed interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense on variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances.

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. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil.

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2012**	2011	2010
(millions of Canadian dollars)			
Amount of unrealized loss recognized in OCI			
Cash flow hedges			
Interest rate contracts	**(1)**	(2)	(25)
	(1)	(2)	(25)
Amount of loss reclassified from accumulated other comprehensive loss to earnings *(effective portion)*			
Interest rate contracts[1]	**2**	3	3
	2	3	3

1 Loss reported within Interest expense in the Consolidated Statements of Earnings.

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.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, 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 and 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. As at December 31, 2012, the Company had filed a preliminary shelf prospectus, and the final shelf prospectus was filed in January 2013. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables 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, 2012. 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.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair 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 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.

The Company's investment in IPL System Inc., an affiliate company, is carried at cost of $825 million at December 31, 2012 (2011 - $825 million), which approximates its fair value and redemption value. At December 31, 2012, the Company's long-term debt had a carrying value of $2,387 million (2011 - $2,387 million) and a fair value of $2,994 million (2011 - $2,943 million).

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 16 of the 2012 Annual Consolidated Financial Statements.

GENERAL BUSINESS RISKS

Network Operating Risk

The Company's network is exposed to operational risks such as accidental damage to mains and service lines, corrosion leaks in mains and service lines, malfunction of compression, regulation and measurement equipment and other issues that can lead to unplanned natural gas escapes and outages. Leaks in the distribution system are an inherent risk of operations. Surveillance, maintenance and repair programs as well as the phased replacement of targeted pipes significantly reduces the exposure. In 2012, the Company completed its cast iron replacement and bare steel main replacement program.

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 extensive programs to manage pipeline integrity, which include the development and use of in-line inspection tools for high stress pipelines. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as the need is identified. The Company also maintains comprehensive insurance coverage for significant pipeline events and has a 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.

Insurance Risk
The Company participates in a comprehensive insurance program which is maintained by Enbridge for its subsidiaries and affiliates. The program includes commercial liability insurance coverage and coverage for environmental incidents, taking into account coverage levels considered customary for its industry and the insurance market at the time of renewal. In the unlikely event multiple insurable incidents exceeding coverage limits are experienced by Enbridge subsidiaries or affiliates within the same insurance period, the total insurance coverage will be allocated on an equitable basis.

Environmental, Health and Safety Risk
The Company's operations and facilities 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, or facilities to which it provides operating services, 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. Ongoing training is provided to ensure employee and contractor competency as well as to enhance the safety culture in the Company. Regular reviews and audits are conducted to assess compliance with legislation and Company policy.

Climate Change Legislation

Federal and Provincial carbon regulations remain in development. With the withdrawal of Canada from the Kyoto protocol, sector specific carbon related regulations may develop. It is currently unclear how natural gas distributors will be specifically treated.

Ontario is a signatory to the Western Climate Initiative and is currently developing proposed greenhouse gas (GHG) reduction programs with stakeholder consultations. An implementation date has not been specified. The Company reports GHG emissions in Ontario, and all reported data is verified by a third party. The Company continues to monitor developments and attend stakeholder consultations in Ontario.

The Company has successfully deployed a carbon data management system to help with the data capture and mandatory and voluntary reporting needs of the Company. The Company continues to publicly report its GHG emissions and will continue to develop internal procedures to identify operationally related GHG reductions. The Company was nominated to the 2012 Canada 200 Carbon Disclosure Leadership Index.

Reputation Risk

The Company's reputation is one of its most valuable assets. 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, Climate Change Policy, Aboriginal and Native American Policy and initiatives such as the Neutral Footprint Initiative and the Company's commitment to Green Energy).

Systems Security Incident

The Company's infrastructure, applications and data are becoming more integrated, creating increased risk a failure in one system could lead to a failure of another system. There is also increasing industry-wide cyber-attacking activities targeting industrial control systems. A successful cyber-attack could lead to unavailability, disruption or loss of key functionalities within the Company's industrial control systems.

The Company has broadened the scope and frequency of vulnerability assessments aimed at identification of potentially exposed information systems. The Company also executed a company-wide security education and awareness program in the past year. The Company benefits from a centralized enterprise information office which supports the development of standardized systems, use of industry proven packages where feasible, use of an information security risk management strategy and disaster recovery plans for critical operations. Back-up computers are used to provide protection against system failure.

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, 2012 of $5,532 million (2011 - $5,336 million), or 70% of total assets (2011 - 69%), 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 2011. 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 U.S. 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, 2012, the Company's regulatory assets totaled $446 million (2011 - $301 million) and regulatory liabilities totaled $906 million (2011 - $848 million). To the extent that the Regulators' future actions differ from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POSTRETIREMENT BENEFITS

The Company maintains pension plans, which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees and 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.

The difference between the actual and expected return on plan assets was an excess of $10 million for the year ended December 31, 2012 (2011 - $38 million shortfall) as disclosed in Note 18 to the 2012

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 2013 will be $45 million.

The following sensitivity analysis identifies the impact on the December 31, 2012 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	61	6	8	1
Decrease in expected return on assets	-	3	N/A	N/A
Decrease in rate of salary increase	(8)	(1)	-	-

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 21 of the 2012 Annual Consolidated Financial Statements.

REGULATORY GOVERNANCE

Undertakings

The Company, and its parent Enbridge, have entered into Undertakings with the Lieutenant Governor in Council for Ontario that commit Enbridge 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.

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.

CHANGES IN ACCOUNTING POLICIES

United States Generally Accepted Accounting Principles
The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada.

To facilitate users' understanding of the transition to U.S. GAAP, the Company restated its 2011 consolidated financial statements, which were originally prepared in accordance with Canadian GAAP to U.S. GAAP, including full comparative information and related note disclosure. The 2011 U.S. GAAP financial statements were filed with securities regulators in Canada and are available on SEDAR at www.sedar.com.

Fair Value Measurement
Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the Financial Accounting Standard Board's joint project with the International Accounting Standards Board. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in the Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the Company does not hold any Level 3 instruments, the adoption of this update did not have an impact on the Company's consolidated financial statements.

Statement of Comprehensive Income
Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and OCI either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive statements of earnings and OCI. The adoption of this standard did not affect the Company's presentation of comprehensive income and did not impact the Company's consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Balance Sheet Offsetting

In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. The adoption of the pronouncement affects financial statement disclosures only and is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning on or after January 1, 2013.

ENBRIDGE GAS DISTRIBUTION INC.
HIGHLIGHTS

Year ended December 31,	**2012**	2011
Financial *(millions of Canadian dollars)*		
Gas commodity and distribution revenue	**1,869**	1,880
Transportation of gas for customers	**345**	421
Other revenue	**202**	103
Total revenue	**2,416**	2,404
Gas commodity and distribution costs excluding depreciation	**(1,199)**	(1,268)
	1,217	1,136
Earnings from continuing operations	**230**	191
Earnings from discontinued operations	**4**	2
Earnings	**234**	193
Earnings attributable to the common shareholder	**232**	191
Return on equity[1] (%)	**10.1**	8.4
Operating		
Volumetric statistics *(millions of cubic metres)*		
Gas commodity sales	**6,171**	6,257
Transportation of gas for customers	**4,572**	5,370
Unbundled volumes[2]	**444**	434
Total volume	**11,187**	12,061
Number of active customers[3] *(thousands)*	**2,032**	1,997
Heating degree days[4]		
Actual	**3,194**	3,597
Forecast based on normal weather	**3,532**	3,602

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. *Number of 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 distribution 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 Greater Toronto Area.*