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

Lesley Austin
Regulatory Coordinator, Regualtory Affairs
Tel 416-495-6505
Fax 416-495-6072
Email: Lesley.Austin@enbridge.com

September 30, 2011

VIA RESS, EMAIL and COURIER

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

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge")
2012 Rate Adjustment Application ("Application")
Ontario Energy Board ("Board") File Number EB-2011-0277

In support of Enbridge's application filed on September 1, 2011, enclosed please find Enbridge's pre-filed evidence for the above noted proceeding.

The evidence has been filed through the Board's Regulatory Electronic Submission System ("RESS") and will be available on the Enbridge website at: www.enbridgegas.com/ratecase.

Two paper copies are being forwarded to the Board via courier.

Please contact the undersigned if you have any questions.

Sincerely,

Lesley Austin

Lesley Austin
Regulatory Coordinator, Regulatory Affairs

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

ENBRIDGE

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

Norm Ryckman
Director, Regualtory Affairs
Tel 416-753-6280
Fax 416-495-6072
Email: Norm.Ryckman@enbridge.com

September 1, 2011

VIA RESS, EMAIL and COURIER

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

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge")
2012 Rate Adjustment Application ("Application")
Ontario Energy Board ("Board") File Number EB-2011-0277

Enclosed please find two copies of Enbridge's Application for an Order or Orders approving or fixing just and reasonable rates for the sales, distribution, transmission and storage of gas commencing January 1, 2012.

The Application has been filed through the Board's Regulatory Electronic Submission System and will be available on the Enbridge website at: www.enbridgegas.com/ratecase.

Enbridge will file its evidence in support of this application by September 30, 2011.

Please contact the undersigned if you have any questions.

Yours truly,

Norm Ryckman
Director, Regulatory Affairs

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

A – ADMINISTRATIVE

EXHIBIT LIST

APPLICATION FOR 2012 RATE ADJUSTMENT

Exhibit	Tab	Schedule	Contents	Witness(es)
A – ADMINISTRATIVE				
A	1	1	Exhibit List	R. Bourke
	2	1	Application	F. Cass
	3	1	Approvals Requested	R. Bourke
	4	1	Curriculum Vitae	R. Bourke
	5	1	Draft Issues List	R. Bourke
B – 2012 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION				
B	1	1	2012 Rate Adjustment Summary	R. Bourke
		2	2012 Revenue per Customer Cap Determination	K. Culbert A. Kacicnik D. Small
		3	Inflation Factor	S. Murray
		4	Customer Additions	F. Ahmad
		5	Gas Volume Budget	R. Lei
		6	Budget Degree Days	S. Murray H. Sayyan
		7	Average Use Forecasting Model and Economic Assumptions	S. Murray H. Sayyan
	2	1	Y Factor Power Generation Projects	S. Murray J. Sim
		2	Y Factor DSM Program	K. Culbert

EXHIBIT LIST

Exhibit	Tab	Schedule	Contents	Witness(es)
B – 2012 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION				
B	2	3	Y Factor CIS/Customer Care Cost	K. Culbert
		4	Y Factor Gas Cost and Carrying Cost	K. Culbert
		5	Z Factor Pension Funding Requirement	S. Kancharla R. Lei A. Patel
		6	Z Factor Cross Bores/Sewer Laterals Cost	C. Clark L. Lawler
	3	1	2012 Proposed Rates	J. Collier A. Kacicnik M. Suarez
		2	Rate Schedules	J. Collier A. Kacicnik
		3	2010 Revenues by Rate Class	J. Collier A. Kacicnik
		4	Proposed Volumes and Revenue Recovery by Rate Class	J. Collier A. Kacicnik
		5	Proposed Billed and Unbilled Revenue	J. Collier A. Kacicnik
		6	Summary of Proposed Rate Change by Rate Class	J. Collier A. Kacicnik
		7	Calculation of Gas Supply Charges by Rate Class	J. Collier A. Kacicnik
		8	Detailed Revenue Calculations	J. Collier A. Kacicnik

EXHIBIT LIST

EXHIBIT LIST

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 or fixing rates for the sale, distribution, transmission and storage of gas.

APPLICATION

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

2. Enbridge hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 36 of the Ontario Energy Board Act, 1998, as amended (the "Act") for an Order or Orders approving or fixing just and reasonable rates for the sale, distribution, transmission and storage of gas commencing January 1, 2012.

3. As of January 1, 2012, Enbridge will be entering the fifth year of a five year Incentive Regulation plan approved by the Board in EB-2007-0615. The Board-approved Settlement Agreement in EB-2007-0615 (the "Settlement Agreement") establishes a revenue per customer cap framework for Enbridge's rates over the period from 2008 to 2012. Specifically, the Settlement Agreement provides that the Company's distribution revenue, in each year of the period January 1, 2008 through December 31, 2012 shall be determined by the application of a Distribution Revenue Requirement Per Customer Formula (the "Adjustment Formula").

4. Enbridge applies to the Board for such final, interim or other Orders, accounting orders and deferral and variance accounts as may be necessary in relation to:

   i. the application of the Adjustment Formula for the year commencing January 1, 2012;
   ii. approval of a Z-factor to recover 2012 pension-related costs that are beyond the control of management, as well as a related variance or deferral account;
   iii. approval of a Z-factor to recover 2012 costs resulting from new standards established or adopted by the Technical Standards and Safety Authority for managing the integrity of pipeline systems, including costs of addressing issues with respect to "crossbores", as well as a related variance or deferral account; and
   iv. the continuation of deferral and variance accounts for 2012 and the determination of all other issues that bear upon the Board's approval or fixing of just and reasonable rates for the sale, distribution, transmission and storage of gas by Enbridge for the year commencing January 1, 2012.

5. 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.

6. As a result of this Application, average rate increases will be approximately 2.5% or less for all customer classes on a T-service basis (that is, excluding commodity costs). For residential customers, the average T-service increase will be approximately 2.5% or about $15 annually. As required by the Settlement

Agreement, Enbridge's filing in support of the Application will include detailed evidence explaining the rate changes.

7. In its Decision and Order in Phase 2 of Enbridge's 2009 Rate Adjustment Application (EB-2008-0219), the Board approved a timeline for Enbridge's rate adjustment process to allow for rates to be in place on January 1st of the year of the rate adjustment. The timeline calls for Enbridge to file its Application by September 1st of the year proceeding the year of the rate adjustment, the Board to issue its Notice of Application shortly thereafter, and Enbridge to file its supporting evidence by October 1st.

8. The evidence in support of this Application will be filed by September 30, 2011. Enbridge respectfully requests that the Board establish a process for this Application that is consistent with the timeline approved in the Decision and Order in Phase 2 of EB-2008-0219.

9. 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 or 1-888-659-0685
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: September 1, 2011 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: ______________________
Norm Ryckman,
Director Regulatory Affairs

APPROVALS REQUESTED

1. The Company has filed evidence in support of its determination of the 2012 rate adjustment within the parameters of its Board approved Incentive Regulation ("IR") formula as decided in the EB-2007-0615 proceeding. The exhibits that are primarily related to, and in support of, the 2012 rate adjustment are located in the "B" series of exhibits.

2. The rate schedules filed at Exhibit B, Tab 3, Schedule 2 are the culmination of the 2012 rate adjustment and rate recovery process using the Company's Board Approved IR formula. The Company is requesting Board Approval to implement these rates effective January 1, 2012.

3. The IR model approved by the Board for Enbridge is a Revenue per Customer Cap methodology which utilizes an index of historical inflation (Canadian Gross Domestic Product Implicit Price Index for Final Domestic Demand ("GDP IPI FDD") found at Exhibit B, Schedule 1, Tab 3) and a forecast of degree days, volumes and customer additions, as well as having the capacity to adjust for Y factors and Z factors.

4. The methods, models, and processes used in the determination of the individual elements and sub-elements that are integral to the index of historical inflation or the forecast of degree days, or volumes or customer additions, or Y factors have been examined and subsequently approved by the Board in the Company's recent rate proceedings. There are requests for Y factors included with this application which are extensions or true-ups of Y-factors as previously examined and approved by the Board during the first four years, 2008 to 2011, of Enbridge's IR model.

5. In this application, the Company is requesting the Board's approval of two new Z factors. The first is required to recover the costs associated with the Company's pension funding requirement as estimated by Mercer (Canada) Limited ("Mercer") in 2012 in the amount of $17.7 million. The evidence in defence of this request is located at Exhibit B, Tab 2, Schedule 5. The second Z factor request is for the recovery of capital and O&M costs, on a revenue requirement basis, related to the Company's response to the Cross Bores/Sewer Lateral safety initiative, with evidence located at Exhibit B, Tab 2, Schedule 6.

6. Inherent in the request to approve the 2012 rate adjustment, are the outcomes, methods, models, and processes used in the determination of those elements which underpin the mathematics of the rate adjustment. As a result, the Company is also requesting that the Board accept its:
   i) Forecast of Customer Additions (Exhibit B, Tab 1, Schedule 4);
   ii) Gas Volume Budget (Exhibit B, Tab 1, Schedule 5);
   iii) Forecast of Degree Days (Exhibit B, Tab 1, Schedule 6);
   iv) Forecast of Average Use (Exhibit B, Tab 1, Schedule 7);
   v) Y Factor Power Generation Projects (Exhibit B, Tab 2, Schedule 1);
   vi) Y Factor DSM Program (Exhibit B, Tab 2, Schedule 2);
   vii) Y Factor CIS/Customer Care Costs (Exhibit B, Tab 2, Schedule 3);
   viii) Y Factor Gas Cost and Carrying Costs (Exhibit B, Tab 2, Schedule 4);
   ix) Z Factor Pension Funding Requirement (Exhibit B, Tab 2, Schedule 5);
   x) Z Factor Cross Bores/Sewer Lateral (Exhibit B, Tab 2, Schedule 6); and
   xi) The 2012 adjustment using the Tax Rate and Rule Change VA ("TRRCVA" Exhibit C, Tab 1, Schedule 2).

7. The Company is also requesting that the Board approve for the 2012 Test Year, the deferral and variance accounts as shown in the evidence in this proceeding at Exhibit C, Tab 1, Schedule 1, and the Rate Handbook at Exhibit B, Tab 3, Schedule 2.

CURRICULUM VITAE OF
FAHEEM AHMAD

Experience:	Enbridge Gas Distribution Inc.
	Manager, Customer Portfolio and Policy 2010
	Program Manager, Financial Assessment 2007
	Supervisor, Gas Supply Analysis 2006
	Program Manger, Portfolio Management 2004
	Program Manager, Capital Appropriations 2003
	Senior Advisor, Financial Business Performance 2001
	Enbridge Incorporated
	Financial Analyst, Business and Financial Analysis 2000
	Lahore Electricity Supply Company
	Manager, Operations 1996
Education:	Certified Management Accountant (CMA) Society of Management Accountants, 2004
	Master of Business Administration Wilfred Laurier University, 1999
	Master of Science, Electrical Engineering University of Engineering and Technology, Lahore, Pakistan, 1992
Memberships:	The Society of Management Accountants of Ontario Professional Engineers of Ontario
Appearances:	(Ontario Energy Board) EB-2010-0146 RP-2002-0133

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-2011-0008
EB-2010-0146
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
CLIFFORD F. CLARK, B.Sc.

Experience: Enbridge Gas Distribution Inc.

Manager Special Projects Safety and Training
2011

Manager Special Projects ESTS
2009

Manager Operations, Central Region East
2006

Manager Sales and Delivery, Central Region
2003

Manager Construction, Toronto
2001

Field Manager Toronto Operations
2000

Enbridge Technology Inc.

Manager Technical Services
1997

The Consumers' Gas Company Ltd.

Manager, Planning and Technical Services, Central Region
1990

Supervisor, Planning and Technical Services
1984

Construction and Maintenance Inspector, East Central District
1977

Pipeline Inspector, Metro Toronto
1975

Education: University of Guelph – 1975, Bachelor of Science, Honours Program
Dalhousie University – Halifax – Bachelor of Science Program

Memberships: North American Society of Trenchless Technology,
Director, Cross Bore Safety Association

Appearances:	(Ontario Energy Board) EB-2009-0172 (Leave to Construct) Lakefield (EBA 595) Pickering Gate Station & Reinforcement Whitby CoGen Dale Road Peterborough Reinforcement

CURRICULUM VITAE OF
JACKIE E. COLLIER

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Design
2003

Manager, Rate Research
2000

Senior Rate Research Analyst
1996

Centra Gas Ontario Inc.

Manager, Rate Design
1995

Supervisor, Cost of Service Studies
1990

Education: Bachelor of Business Management
Ryerson Polytechnical Institute, 1988

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

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

CURRICULUM VITAE OF
KEVIN CULBERT

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Accounting
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 (3^{rd} level)
Seneca College 1987-89 (business/accounting)

Appearances: (Ontario Energy Board)
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
TANYA M. FERGUSON

Experience: Enbridge Gas Distribution Inc.

Manager Customer Care Operations, Customer Care
2010

Manager Customer Care Financial Administration, Customer Care
2006

Manager Special Projects, Customer Care
2005

Senior Analyst, Planning and Projects
2002

Supervisor, Internal Reporting
2000

Enbridge Services Inc.

Financial Analyst, Financial Reporting
1999

Enbridge Gas Distribution Inc.

Corporate Accountant, Financial Reporting
1998

Audit Assistant, Audit Services
1998

Accounting Trainee, Financial Reporting
1997

Education: Masters of Business Administration
York University, 2002

Certified Management Accountant
Society of Management Accountants, 2000

Bachelor of Commerce (Honours)
University of Windsor, 1996

Memberships: Certified Management Accountant
Society of Management Accountants

Appearances: (Ontario Energy Board)
EB-2010-0146 2011

(Ontario Energy Board)
EB-2005-0001

(Ontario Energy Board)
RP-2003-0203

CURRICULUM VITAE OF
JOHN JOZSA

Experience:	Enbridge Gas Distribution Inc. Assistant Controller 2007 Manager, Tax Services 2001 University of Toronto at Scarborough Lecturer, Division of Management 1999 - 2009 KPMG, Chartered Accountants Senior Tax Manager 1999 Tax Manager 1997 Revenue Canada, Taxation Corporate Tax Auditor 1993 Ernst & Young, Chartered Accountants Senior Staff Accountant 1989
Education:	CICA In-Depth Tax Course, 1999 Chartered Accountant, 1991 Honours Bachelor of Commerce Degree (Accounting) Laurentian University, 1989
Memberships:	Institute of Chartered Accountants of Ontario
Appearances:	(Ontario Energy Board) EB-2006-0034 RP-2003-0203

CURRICULUM VITAE OF
ANTON KACICNIK

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Research & Design
2007

Manager, Cost Allocation
2003

Program Manager, Opportunity Development
1999

Project Supervisor, Technology & Development
1996

Pipeline Inspector, Construction & Maintenance
1993

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

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
EB-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
SAGAR KANCHARLA

Experience:

Enbridge Gas Distribution Inc.

Director, Business Performance
2011

Director, Strategy, Research & Planning
2008

Manager, Planning & Economics
2007

Manager, Financial and Economic Assessment
2005

Manager, Financial Assessment
2003

Senior Advisor, Financial Assessment
2002

Enbridge Inc.

Financial Analyst, Business & Financial Analysis
2000

GE Silicones India Pvt. Ltd., India

Manager – Market Development
1996

Ciba Specialty Chemicals Ltd., India

Product Manager – Pigments Division
1994

Marketing Executive – Polymers Division
1992

Education:

Masters of Business Administration
McMaster University, 2000

Post Graduate Diploma in Management
Indian Institute of Management, Ahmedabad, India, 1992

Bachelor of Engineering (Civil Engineering)
Andhra University, Visakhapatnam, India, 1990

Membership:

Society of Utility and Regulatory Financial Analysts

Appearances:	(Ontario Energy Board) EB-2007-0615 EB-2006-0066 EB-2006-0034 EB-2005-0539 EB-2005-0001 RP-2004-0015 RP-2003-0203

CURRICULUM VITAE OF
KERRY LAKATOS-HAYWARD

Experience: Enbridge Gas Distribution

Director, Customer Care
2010

Director, Operations Services
2008

Director, Business Development & Strategy
2006

Manager, Business Development & Strategy
2003

Manager, Volumetric & Market Analysis
2000

Manager, Multi-Family Marketing
1997

Senior Economist, Economic Studies
1995

Ontario Hydro

End Use Economist, Load Forecasts
1994

Evaluation Analyst, Planning & Evaluation
1992

Education: Bachelor of Arts (Specialist in Economics)
University of Toronto, 1990

Master of Science in Planning (Environmental Planning)
University of Toronto, 1992

Queen’s Executive Program, 2005

Certificate in Carbon Finance, 2008

Appearances: (Ontario Energy Board)
RP-2006-0034
RP-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040

CURRICULUM VITAE OF
LISA L. LAWLER

Experience:	Enbridge Gas Distribution Inc.
	Director, Integrity 2010
	Chief Engineer 2008
	Manager, Enbridge Ontario Wind Power Project 2006
	Manager, Strategic Distribution Alliance 2004
	Manager, Distribution Planning 2001
	Manager, Operations Eastern Region 1999
	Manager, Distribution Expansion 1997
	General Supervisor, Maintenance (West) 1996
	Supervisor, Construction & Maintenance Administration 1995
	Operations Engineer 1991
	Congas Engineering Canada Limited (a former subsidiary of The Consumers' Gas Company Ltd.) International Marketing Engineer 1989
Education:	Master of Business Administration Wilfrid Laurier University, 1989
	Bachelor of Applied Science, Chemical Engineering, Honours Program University of Waterloo, 1988
Memberships:	Professional Engineers of Ontario
Appearances:	(Ontario Energy Board) Eb-2009-0172 RP-2002-0133

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-2011-0008 EB-2010-0146 EB-2010-0042 EB-2009-0172

CURRICULUM VITAE OF
STUART MURRAY

Experience:	Enbridge Gas Distribution Inc.
	Manager, Investment Review and Economic Analysis 2010
	Manager, Investment Review and Customer Growth 2008
	Manager, Financial Assessment 2006
	Pitney Bowes Canada
	Project Manager, Enterprise Program Office 2003
	Finance Manager, Service Operations 2001
	Finance Manager, New Business Development 2000
	Canadian Tire Corporation
	Business Analyst, Marketing Finance 1997
	Financial Analyst, Corporate Planning 1996
Education:	Master of Business Administration McMaster University, 1995
	B.A. Economics, Administrative & Commercial Studies University of Western Ontario – 1993
Appearances:	(Ontario Energy Board) EB-2010-0146 EB-2006-0034

CURRICULUM VITAE OF
ASHA PATEL

Experience:	Enbridge Gas Distribution Inc.
	Supervisor of Finance Operational Support 2011
	Supervisor of O&M Budgets 2011
	Supervisor of External Reporting and Pensions 2008
	Ernst & Young LLP
	Senior Staff Accountant 2008
	Staff Accountant 2006
Education:	Chartered Accountant Institute of Charted Accountants of Ontario, 2008
	Masters of Accounting University of Waterloo, 2006
	Bachelor of Arts, Honours Accountancy Co-op University of Waterloo, 2005
Memberships:	Institute of Chartered Accountants of Ontario
Appearances:	(Ontario Energy Board) EB-2011-0008

CURRICULUM VITAE OF
HULYA SAYYAN

Experience:	Enbridge Gas Distribution Inc.
	Senior Market Analyst 2007
	Risk Software Technologies
	Economic Specialist 2005
	Marmara University
	Assistant Professor, Econometrics Department 2002
	Instructor, Econometrics Department 2001
	Research Assistant, Econometrics Department 1994
Education:	Ph.D. in Econometrics Marmara University, 2000
	Master of Science in Statistics Marmara University, 1995
	Bachelor of Science in Statistics Mimar Sinan University, 1992
Memberships:	Toronto Association for Business & Economics (CABE)
Appearances:	(Ontario Energy Board) EB-2010-0146

CURRICULUM VITAE OF
JEFFREY SIM

Experience:	Enbridge Gas Distribution Inc.
	Manager, Strategic Accounts, Direct Purchase 2010
	Manager, Market Development, Distributed Energy 2006
	Business Manager, Distributed Energy 2002
	Supervisor, Gas Supply Planning 1997
	Gas Controller, Gas Control 1988
	Technologist, Laboratory Services 1983
	Technician, Laboratory Services 1978
Education:	Undergraduate, B. Sc., University of Toronto, 1976
Memberships:	Association of Power Producers of Ontario Board Member, Fuel Cells Canada, 2005-2008
Appearances:	(Ontario Energy Board) EB-2010-0310 EB-2010-0146

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-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
MARGARITA SUAREZ-SHARMA

Experience:	Enbridge Gas Distribution Inc.
	Manager, Cost Allocation 2008
	Manager, DSM Reporting & Analysis 2005
	Analyst, Rate Design 2004
	Senior Analyst, DSM Planning and Evaluation 2002
	Senior Economic Analyst, Economic & Financial Studies 1998
	Margaret Chase Smith Center for Public Policy
	Research Assistant 1995
Education:	Master of Arts in Economics University of Maine, 1995
	Bachelor of Arts in Economics University of Maine, 1993
Appearances:	(ONTARIO ENERGY BOARD) EB-2011-0008 EB-2010-0146 EB-2010-0042 EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2008-0106
	(RÉGIE DE L'ÉNERGIE) R-3724-2010 R-3692-2009 R-3665-2008

CURRICULUM VITAE OF
BARRY C. YUZWA

Experience:	Enbridge Gas Distribution Inc.
	Director, Finance & Control 2010
	Enbridge Inc.
	Senior Director, Chief Audit Executive Audit Services & Internal Controls 2007
	Director, Audit Services 1999
	Safeway Inc./Canada Safeway Limited
	Manager, Corporate Audit Services 1991
	Deloitte & Touche
	Audit Manager 1987
Education:	Certified Internal Auditor Institute of Internal Auditors 2003
	Chartered Accountant Canadian Institute of Chartered Accountants 1986
	Bachelor of Commerce-Accounting University of Calgary 1983
Memberships:	Canadian Institute of Chartered Accountants Institute of Chartered Accountants of Alberta Institute of Chartered Accountants of Ontario Institute of Internal Auditors Financial Executives International, Canada Corporate Executive Board, Audit Directors and Risk Management Advisory Council University of Calgary, Haskayne School of Business, Mentorship Program Enbridge Inc. Mentorship Program
Appearances:	(Ontario Energy Board) EB-2011-0008

DRAFT ISSUES LIST

1) Has Enbridge calculated its proposed distribution revenue requirement, including the assignment of that revenue requirement to the rate classes and the resulting rates, in accordance with the EB-2007-0615 incentive settlement agreement?

2) Is the forecast of customer additions appropriate?

3) Is the gas volume budget appropriate?

4) Is the forecast of degree days appropriate?

5) Is the forecast of average use appropriate?

6) Is the amount proposed for the Y factor Power Generation Projects appropriate?

7) Is the amount proposed for the Y factor DSM Program appropriate?

8) Is the amount proposed for the Y factor CIS/Customer Care Costs appropriate?

9) Is the amount proposed for the Y factor Gas Cost & Carrying Costs appropriate?

10) Is the amount proposed for the Z factor Pension Funding Requirement appropriate?

11) Is the amount proposed for the Z factor Cross Bores/Sewer Laterals Costs appropriate?

12) Is the adjustment calculated for the 2012 Tax Rate and Rule Change Variance Account (“TRRCVA”) appropriate?

13) Is it appropriate to approve the Company’s requested deferral (“DA”) and variance (“VA”) accounts as evidenced at Exhibit C, Tab 1, Schedule 1?

14) Is it appropriate to approve the Company’s Rate Handbook filed at Exhibit B, Tab 3, Schedule 2?

15) How should the new rates be implemented?

Witness: R. Bourke

B – 2012 RATE ADJUSTMENT
CALCULATION AND
SUPPORTING INFORMATION

1

<u>2012 RATE ADJUSTMENT SUMMARY</u>

1. The Company is proposing to adjust its rates for the 2012 fiscal year within the parameters established in the Board Approved Incentive Regulation ("IR") formula (EB-2007-0615 dated February 4, 2008). The Settlement Agreement from that proceeding has been filed at Exhibit E, Tab 1, Schedule 1 for reference in this proceeding.

2. The Company anticipates an approach which will adjust rates to be implemented effective January 1, 2012 within the time constraints stipulated by the Board in its Decision in the 2009 rate adjustment proceeding EB-2008-0219 dated July 14, 2009. The Company's application has been filed at Exhibit A, Tab 2, Schedule 1.

3. The evidence supporting the mechanical aspects, as well as the supporting material for the proposed Y and Z factor amounts included in the proposed 2012 rate adjustment, have been filed primarily in the "B" series of exhibits. The 2012 revenue per customer cap determination is filed at Exhibit B, Tab 1, Schedule 2, with supporting materials found in the balance of the schedules filed under Exhibit B, Tab 1, and evidence in support of the Y and Z factors filed under Tab 2.

4. The proposed rate schedules are found at Exhibit B, Tab 3, Schedule 2, with the balance of the schedules filed in Tab 3 representing material that has been submitted in support of the development of the rate schedules.

5. The 2010 historical year information was filed, reviewed and adjudicated in the EB-2011-0008 Earnings Sharing Mechanism ("ESM") proceeding. That material is available (1) on the Board's Advanced Regulatory Document Search ("RDS")

website under docket EB-2011-0008, or (2) in electronic format on EGD’s website at: www.enbridgegas.com/about/regulatory-affairs, under Other Regulatory Proceedings.

6. The information provided in the “E” series of exhibits has been filed for reference purposes.

2012 REVENUE PER CUSTOMER CAP, DISTRIBUTION AND
TOTAL REVENUE DETERMINATION

Row		Col. 1 2012
1.	2011 Total Approved Revenue ($millions)	2,404.9
2.	Gas Costs to operations (at Oct. 1, 2010 ref. price)	1,416.3
3.	2011 Approved Distribution Revenue	988.6
4.	2011 Gas in storage related carrying costs (at Oct. 1, 2010 ref. price)	(30.9)
5.	DSM 2011 amount	(26.7)
6.	CIS / Cust. Care 2011 amount	(97.4)
7.	Power generation projects 2011 amount	(3.5)
8.	Distribution Revenue Sub-total	830.1
9.	Ratepayer 50% share of 2012 incremental tax amounts	(4.6)
10.	Distribution Revenue base (subject to the escalation formula, $millions)	825.5
11.	Average Number of Customers (Beginning)	1,965,537
12.	Distribution Revenue per Customer 2012 (Beginning)	$ 419.99
13.	GDP IPI FDD	1.72%
14.	Inflation Coefficient (allowed % of GDP IPI FDD)	45.00%
15.	Escalation Factor, 100 plus (GDP IPI FDD multiplied by the inflation coeff.)	100.77%
16.	Distribution Revenue per Customer 2012 (Ending)	$ 423.23
17.	Average Number of Customers (Ending)	1,984,734
18.	Distribution Revenue (resulting from the escalation formula, $millions)	839.99
	Y-Factors	
19.	2012 Gas in storage related carrying costs (at October 1, 2011 ref. price)	30.60
20.	2012 DSM Y-factor amount	30.90
21.	CIS / Customer Care 2012 approved amount	99.20
22.	Power generation projects 2012 amount	6.60
23.	Total 2012 Y-Factors	167.30
	Z-Factors	
24.	2012 Pension funding requirement	17.70
25.	2012 Crossbore / Sewer Lateral program requirement	3.80
26.	Total 2012 Z-Factors	21.50
27.	Total 2012 Distribution Revenues	1,028.79
28.	2012 Gas Costs to operations (at October 1, 2011 ref. price)	1,515.50
29.	2012 Total Revenue ($millions)	2,544.29

Witnesses: K. Culbert
A. Kacicnik
D. Small

2012 DISTRIBUTION REVENUE PER CUSTOMER CAP
DISTRIBUTION AND TOTAL REVENUE DETERMINATION (2012)

1. Enbridge's revenue per customer cap calculation for 2012 has been determined through the continued use and updating of various components or elements of the Incentive Regulation model and revenue determination formula which was approved by the Board in EGD's 2008 rate proceeding, EB-2007-0615.

2. As shown on page 1 of this schedule, the 2012 total revenue amount to be collected through rates is calculated through the completion of the following process. Formula amounts and percentages being referred to below are all found in Column 1 of page 1.

Process

3. Row 1, $2,404.9 million, the starting point of the calculation, is the 2011 Total Board Approved revenue as per the EB-2010-0146 Final Rate Order. (Appendix A, page 1, Column 1, Line 26)

4. Row 2 eliminates gas costs of $1,416.3 million embedded within that total approved revenue to arrive at Row 3, the 2011 Board Approved distribution revenue of $988.6 million. Removal of this gas cost is necessary as it was based on prices underpinning the October 1, 2010 gas cost reference price of $204.864 /10^{3}m^3 and was relative to 2011 approved volumes[1]. The elimination is required in order to establish a base distribution revenue upon which the incentive escalation formula can be applied exclusive of gas costs. A 2012 forecast of gas costs, outside of the

[1] That reference price has been replaced within rates throughout each quarter in 2010. Prices underpinning the Oct. 1, 2010 reference price are embedded in the 2011 forecast of gas cost at the time of the 2011 application.

Witnesses: K. Culbert
A. Kacicnik
D. Small

incentive escalation formula, is included into the 2012 total revenue at Row 28, and is explained later in this evidence.

5. Row 3 shows the 2011 Board Approved distribution revenue of $988.6 million, to which the following further adjustments are required in order to calculate the distribution revenue upon which the incentive escalation formula can be applied within the context of EGD’s approved revenue per customer cap model.

6. Row 4 eliminates $30.9 million, which is the embedded carrying cost on gas in storage and working cash related to gas costs in the 2011 Board Decision which are eliminated and explained at Row 2 above. Similar to Row 2, this elimination is required in order to remove the carrying cost on gas in storage and gas cost working cash embedded in the 2011 Board Approved distribution revenue which was based on 2011 approved volumes and prices underpinning the October 1, 2010 gas cost reference price of $204.864 /$10^3m^3$. This elimination contributes to the establishment of the distribution revenue upon which the incentive escalation formula can be applied exclusive of carrying costs on 2011 gas in storage and gas cost working cash amounts related to 2011 approved volumes and gas cost prices. A carrying cost on gas in storage and gas cost working cash for 2012, outside of the incentive escalation formula, is included in the 2012 total revenue and explained at Row 19 later in this process. (Ref. Exhibit B, Tab 1, Schedule 2, Appendix A)

7. Row 5 removes the 2011 Board Approved DSM operating costs of $26.7 million as established within the EB-2010-0146 Decision. This adjustment is necessary as DSM operating cost budgets are approved in separate proceedings, therefore the base distribution revenue upon which the incentive escalation formula can be applied needs to exclude DSM approved amounts. A 2012 DSM operating budget

of $30.9 million as allowed within the EB-2008-0346 guidelines, is included into the 2012 total revenue outside of the incentive escalation formula at Row 20.

8. Row 6 removes the 2011 Board Approved CIS/Customer Care costs of $97.4 million (exclusive of bad debt) (shown at Appendix F in the EB-2007-0615 Rate Order). This adjustment is necessary as the base distribution revenue upon which the incentive escalation formula is to be applied should exclude CIS/Customer Care costs. The 2012 Approved CIS/Customer Care costs are included into the 2012 distribution revenue, outside of the incentive escalation formula, and are further outlined at Row 21.

9. Row 7 removes the 2011 Board Approved power generation related Y factor revenue requirement amount of $3.5 million from the base subject to escalation. The inclusion of an updated 2012 revenue requirement amount of $6.6 million is shown at Row 22. The power generation project cost treatment was approved to be handled outside of the escalation portion of the incentive formula.

10. Row 8 shows the distribution revenue sub-total of $830.1 million inclusive of all of the above noted adjustments. This is the exact amount of the Board Approved formula portion of 2011 rates as shown at Appendix A, page 1, Column 1, Row 18 of the EB-2010-0146 Rate Order.

11. Row 9 incorporates an incremental reduction to base rates of $4.6 million, which is the 2012 ratepayer amount relating to incremental tax rate and rule change expectations, agreed to be shared equally between ratepayers and the Company. Within the EB-2011-0008 proceeding, the Company filed and the OEB approved evidence which updated the previous approved tax savings and sharing agreement.

Witnesses: K. Culbert
A. Kacicnik
D. Small

The Company has filed evidence at Exhibit C, Tab 1, Schedule 4 in this proceeding which explains the reason for and results of the update being incorporated within this 2012 rate application.

12. Row 10 shows the total base distribution revenue of $825.5 million, upon which the approved incentive escalation formula can be applied.

13. Row 11 provides the 2011 Board Approved average number of customers of 1,965,537 (from EB-2010-0146, Rate Order, Appendix A, p. 1, Column 1, Row 17) which is used in the next step of this process to calculate the base distribution revenue/customer before 2012 Y factor amounts.

14. Row 12 is the base distribution revenue per customer of $419.99, which is derived by dividing the Row 10 base distribution revenue of $825.5 million by the 2011 approved average customers of 1,965,537.

15. Row 13, 1.72%, is the updated GDP IPI FDD inflation factor component of the EB-2007-0615 Board Approved incentive escalation formula which is found in evidence at Exhibit B, Tab 1, Schedule 3.

16. Row 14, 45%, is the 2012 inflation co-efficient component of the incentive escalation formula as approved by the Board in the EB-2007-0615 Rate Order, Appendix A, page 1, Column 5, Row 15.

17. Row 15, 100.77% (or a multiplier of 1.0077) is the adjustment factor calculated as, 100% plus 0.77% (0.77% is calculated as the GDP IPI FDD inflation factor of 1.72%

multiplied by 45%) which is required in the next step to arrive at an escalated average distribution revenue per customer amount.

18. Row 16, $423.23, is the 2012 distribution revenue per customer which is calculated by multiplying the distribution revenue per customer at Row 12 of $419.99 by the adjustment factor of 100.77% or a multiplier of 1.0077.

19. Row 17 provides the 2012 forecast average number of customers of 1,984,734 which is found in evidence at Exhibit B, Tab 1, Schedule 5.

20. Row 18, $839.99 million, is the 2012 distribution revenue which is calculated by multiplying the 2012 distribution revenue per customer amount of $423.23 by the forecast 2012 average number of customers of 1,984,734. This distribution revenue is further adjusted in Rows 19 through 28 to arrive at the 2012 total revenue for which 2012 rates are developed.

21. Row 19 increases the $839.99 distribution revenue by $30.6 million for carrying costs on 2012 gas in storage and gas cost working cash. As explained in the Row 4 narrative, just as the carrying costs embedded in the Board's 2011 approved distribution revenue need to be removed from a base in order to apply an incentive escalation formula, the 2012 carrying cost on gas in storage and gas cost working cash related to 2012 forecast volumes and prices underpinning the October 1, 2011 gas cost reference price need to be included in the 2012 total revenue. This type of adjustment is required in order to develop rates which incorporate the upcoming 2012 volumetric forecasts and changes in approved gas prices, (Ref. Exhibit B, Tab 1, Schedule 2, Appendix A) and in order to ensure a proper baseline to which

EGD's current approved rates which contain the October 1, 2011 approved gas cost reference price and associated carrying cost impacts can be compared.

22. Row 20 increases the $839.99 million distribution revenue by $30.9 million, which is the Company's proposed 2012 DSM operating cost budget in accordance with the EB-2008-0346 guidelines dated June 30, 2011, and as will be included in evidence in the Company's 2012 DSM Plan proceeding, EB-2011-0295. The addition of 2012 DSM costs, to 2012 total revenue, is required as 2011 DSM costs were previously removed as explained in the narrative for Row 5.

23. Row 21 increases the $839.99 million distribution revenue by $99.2 million, the 2012 amount of CIS/Customer Care costs which, as previously mentioned in the Row 6 narrative, is shown in the template and true-up mechanism as approved by the Board in Appendix F in the EB-2007-0615 Rate Order.

24. Row 22, $6.6 million, represents the 2012 revenue requirement associated with Y factor capital expenditures for power generation projects which the Board approved the inclusion of within EGD's Incentive Regulation formula and determination. Evidence is found at Exhibit B, Tab 2, Schedule 1, Appendix A.

25. Row 23, $167.3 million, is the sum of Rows 19 through 22, total 2012 Y factors.

26. Row 24, $17.7 million, represents the Company's forecast 2012 pension funding requirement being requested to be established as a Z factor within the context of the IR model settlement agreement approved in EB-2007-0615. Evidence supporting the recovery and treatment of this item and amount is shown at Exhibit B, Tab 2, Schedule 5, and Exhibit C, Tab 1, Schedule 2.

Witnesses: K. Culbert
A. Kacicnik
D. Small

27. Row 25, $3.8 million, represents the Company's forecast 2012 cross bore/sewer lateral program revenue requirement being requested to be established as a Z factor within the context of the IR model settlement agreement approved in EB-2007-0615. Evidence supporting the recovery and treatment of this item and amount is shown at Exhibit B, Tab 2, Schedule 6, and Exhibit C, Tab 1, Schedule 3.

28. Row 26, $21.5 million, is the sum of rows 24 and 25, total 2012 Z factors.

29. Row 27, $1,028.79 million, is Enbridge's total 2012 distribution revenue before gas costs which 2012 rates will be designed to recover.

30. Row 28, $1,515.5 million, is the 2012 forecast gas cost required to be added to the 2012 distribution revenue to establish 2012 total required revenue. The $1,515.5 million replaces the previously removed 2011 gas cost value embedded within the starting 2011 Total Board Approved revenue as explained in the narrative for Row 2. Evidence is found at Exhibits B, Tab 4, Schedules 1 and 2.

31. Row 29, $2,544.29 million, is the 2012 total revenue arrived at and to be used to design rates, following the application of the sum of all of the elements of the agreed upon incentive escalation formula. The 2012 rates will be designed to recover this entire amount based on the forecast of 2012 volumes associated with the formula.

Witnesses: K. Culbert
A. Kacicnik
D. Small

2012 Forecast Gas in Storage
In Rate Base and its Associated
Gross Carrying Cost

Line No.		Col.1 Exhibit Reference	Col.2	Col.3
				($000)
		EB-2011-0277	(10^3m^3)	
1.	Average gas in storage volume & value	Exhibit B.T4.S2.pg.4, line 14	1 188 148.7	301,951.2
2.	Gas cost working cash allowance			
2.1	a) Purchase cost of gas		$1,596,269.8	
2.2	b) Net lag-days calculated	EB-2011-0296,Q4-3.T2.S2.line 3.2	5.8	
2.3	c) Dollar days		9,258,364.8	
2.4	d) Number of operating days		366	25,296.1
3.	Rate Base value			327,247.3
4.	Gross return component	(See page 3 of this schedule)		9.36%
5.	Carrying cost requirement			30,630.3

2011 Forecast Gas in Storage
In Rate Base and its Associated
Gross Carrying Cost

Line No.		Col.1 Exhibit Reference	Col.2	Col.3
				($000)
		EB-2010-0146	(10^3m^3)	
1.	Average gas in storage volume & value	Exhibit B.T4.S2.pg.4, line 14	1 157 979.4	306,558.7
2.	Gas cost working cash allowance			
2.1	a) Purchase cost of gas		$1,489,087.8	
2.2	b) Net lag-days calculated	EB-2010-0258,Q4-3.T2.S2.line 3.2	5.8	
2.3	c) Dollar days		8,636,709.2	
2.4	d) Number of operating days		365	23,662.2
3.	Rate Base value			330,220.9
4.	Gross return component	(See page 3 of this schedule)		9.36%
5.	Carrying cost requirement			30,908.7

Calculation of the Gross Rate of Return on Rate Base

Line No.		Col.1 Capital Structure Component (Note 1)	Col.2 Indicated Cost Rate (Note 1)	Col.3 Net Return Component (Note 1)	Col.4 Reciprocal of the Tax rate (Note 2)	Col.5 Gross Return Component
		%	%	%		%
1.	Long-term debt	59.65	7.31	4.36		4.36
2.	Short-term debt	1.68	4.12	0.07		0.07
3.	Tax shielded	61.33		4.43		4.43
4.	Preference shares	2.67	5.00	0.13	0.6388	0.20
5.	Common equity	36.00	8.39	3.02	0.6388	4.73
6.	Non tax shielded	38.67		3.15		4.93
7.		100.00		7.58		9.36

Note 1: The source for Columns 1 to 3 is the cost of capital found in the EB-2006-0034 Final Rate Order, Appendix A, Schedule 4, Pg 1, Columns 2 to 4, Issued: 2007-09-24.

Note 2: The Corporate Income Tax rate was forecast at 36.12% for the Company's fiscal year.

INFLATION FACTOR

1. The purpose of this evidence is to provide the inflation factor used in the Company's revenue cap per customer incentive regulation formula. The Company has calculated the inflation factor for 2012 using the Canadian Gross Domestic Product Implicit Price Index for Final Domestic Demand ("GDP IPI FDD").

2. In accordance with the Board's Decision in the Company's EB-2007-0615 rate case, the inflation factor (I) is to be reset each year during the term of the incentive regulation plan using the most recent trend in GDP IPI FDD. The recent trend in GDP IPI FDD is calculated as the arithmetic average of the most recent four quarters of annualized growth (AG) rates in the index as follows[1]:

$$I_{TestYear} = \frac{1}{4}\left(AG^{Q2}_{TestYear-1} + AG^{Q1}_{TestYear-1} + AG^{Q4}_{TestYear-2} + AG^{Q3}_{TestYear-2}\right)$$

where, for example,

$$AG^{Q2}_{TestYear-1} = 100\left(\frac{Index^{Q2}_{TestYear-1}}{Index^{Q2}_{TestYear-2}} - 1\right)$$

3. The time series used to calculate the inflation factor is as follows:

Series Title:	Canada; Implicit Price Indexes 2002=100; Final Domestic Demand; Quarterly
Source:	Statistics Canada, CANSIM II Database
Table:	380-0003
V-number:	V1997757

[1] Canadian GDP IPI FDD is produced on a quarterly basis by Statistics Canada. Data releases are typically lagged by 2 months. For example, the Q1 2007 index would be available in May of 2007. Assuming a rate application filing in September of each year this would mean that the Q2 value of the index would be available at, or shortly before, the time of filing.

Witness: S. Murray

4. Table 1 outlines the calculation of the inflation factor for 2012. The average of annualized growth rates for the most recent 4 quarters is rounded to 2 decimal places. Based on the recent trend in GDP IPI FDD, the inflation factor for 2012 is 1.72%.

Table 1 - Inflation Factor
Calculation of Inflation Factor

Col. 1	*Col. 2*	*Col. 3*
Quarter	Index Value	Annualized Growth Rate
2008 Q4	114.20	
2009 Q1	114.40	
2009 Q2	114.50	
2009 Q3	114.40	
2009 Q4	114.90	
2010 Q1	115.40	
2010 Q2	115.60	
2010 Q3	116.10	1.49%
2010 Q4	116.70	1.57%
2011 Q1	117.50	1.82%
2011 Q2	117.90	1.99%
Average (Rounded to 2 decimal places)		1.72%

CUSTOMER ADDITIONS

1. The purpose of this evidence is to provide the Company's forecast of customer additions for the Company's 2012 Test Year. The Company is forecasting 37,927 customer additions for 2012. This represents an increase of 1,690 customer additions relative to the 2011 Board approved forecast of 36,237 customer additions.

2. The customer additions forecast for 2012 has been developed using a grass roots approach. Using economic information and inputs from builders, Regional Operations provide a bottom up forecast of the expected number of customer additions for the upcoming year. This approach has been used by the Company for over a decade in previous rate applications and replicates a process that has been accepted in settlement proposals and Board decisions.

Economy

3. Economic conditions in Ontario have continued to recover since the second half of 2009. This recovery follows four consecutive quarters of declines from the third quarter of 2008 to the second quarter of 2009. Real output in the Ontario economy has increased for seven consecutive quarters beginning in the third quarter of 2009. In the first quarter of 2011, Ontario real gross domestic product increased, quarter over quarter, by 0.8% or 3.2% annualized. This increase in economic output can be attributed to a variety of factors including the relative financial market stability in Canada and the end to the recession in the U.S., Canada and abroad which has resulted in increasing government, consumer and business spending. Manufacturing, particularly the automotive sector, and exports in general, have registered positive growth rates since the third quarter of 2009. As a result of the

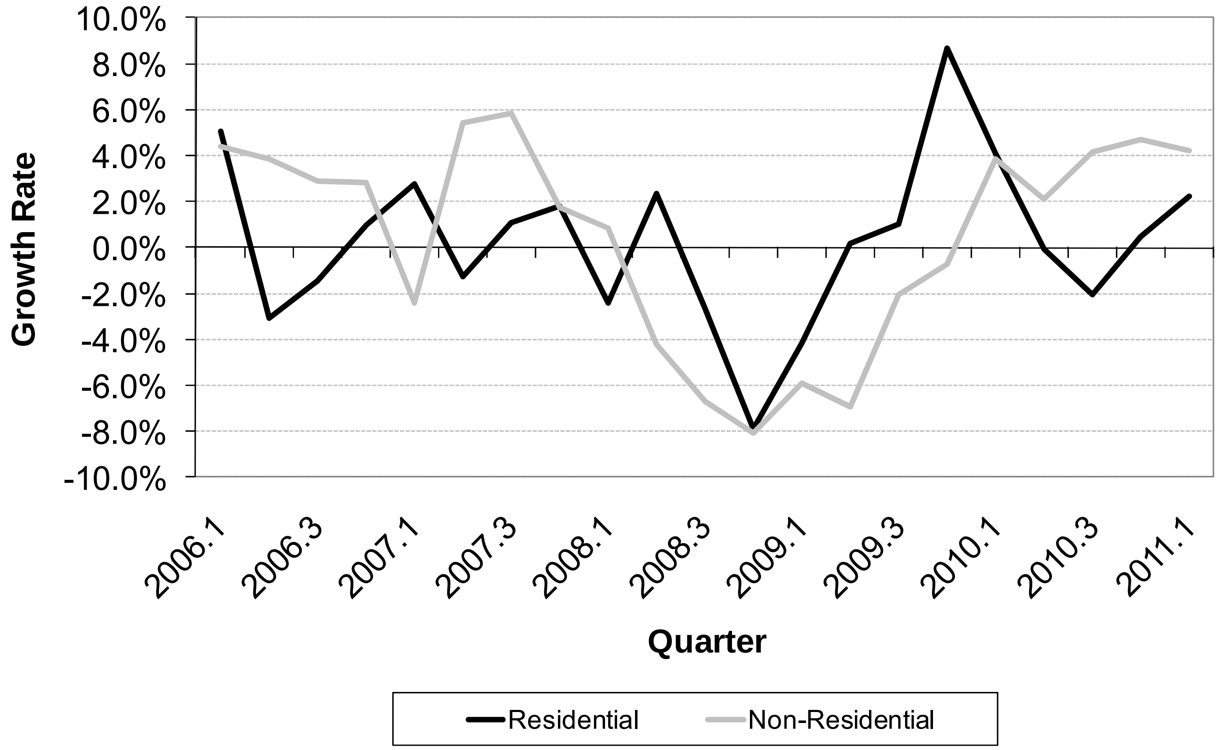
increase in economic activity, the number of individuals employed has increased noticeably resulting in lower unemployment rates and higher disposable incomes. Projections for real GDP growth over the next two years for Ontario are on average in line with the growth rates seen for the past five years. Table 1 contains a summary of the Company's Economic Outlook Spring 2011. Detailed tables outlining the Economic Outlook can be found at Exhibit C, Tab 2, Schedule 3, pages 21 to 24.

Table 1
Economic Outlook Summary

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Variable	2006	2007	2008	2009	2010	2011 Forecast	2012 Forecast
ONTARIO REAL GDP (% CHANGE)	2.4	2.0	-0.9	-3.6	2.8	2.6	2.5
MORTGAGE RATE 5 YEAR TERM (%)	6.66	7.07	7.06	5.63	5.61	5.46	6.06
ONTARIO HOUSING STARTS (000's)	73.4	68.1	75.1	50.4	60.4	57.0	59.6
CENTRAL REGION HOUSING STARTS (000's)	38.8	35.7	42.4	25.8	30.9	29.4	30.8
EASTERN REGION HOUSING STARTS (000's)	6.1	6.8	7.2	6.0	6.6	6.3	6.6
NIAGARA REGION HOUSING STARTS (000's)	1.4	1.3	1.3	1.0	1.3	1.2	1.3
FRANCHISE AREA HOUSING STARTS (000's)	46.4	43.8	50.8	32.7	38.8	37.0	38.7

4. Commensurate with the increase of overall economic growth, Ontario real gross fixed capital formation in both residential and non-residential construction has also increased. Figure 1 shows that the growth rate in real business fixed investment for both residential and non-residential structures has trended higher over the past few quarters.

Figure 1: Ontario Real Gross Fixed Capital Formation



5. The most recent peak in Ontario housing starts occurred in 2003. At that point in time the target for the overnight rate set by the Bank of Canada was near historical lows, averaging 2.94% for the year. Recently the Bank of Canada had aggressively reduced interest rates in an attempt to free up credit and smooth the impact of the global economic slowdown on Canada's economy. A new historic low was set in 2009 as the Bank of Canada dropped the target for the overnight rate to a mere 25 basis points and maintained the overnight rate at this level until May 2010. Since May of 2010, the Bank of Canada has raised the overnight rate 75 basis points to 1.00%. The expectation is that the Bank of Canada will begin to raise the overnight rate further in 2011 and through 2012. As a result of the low overnight rate, mortgage rates have remained very low in historic terms, but given the expectation

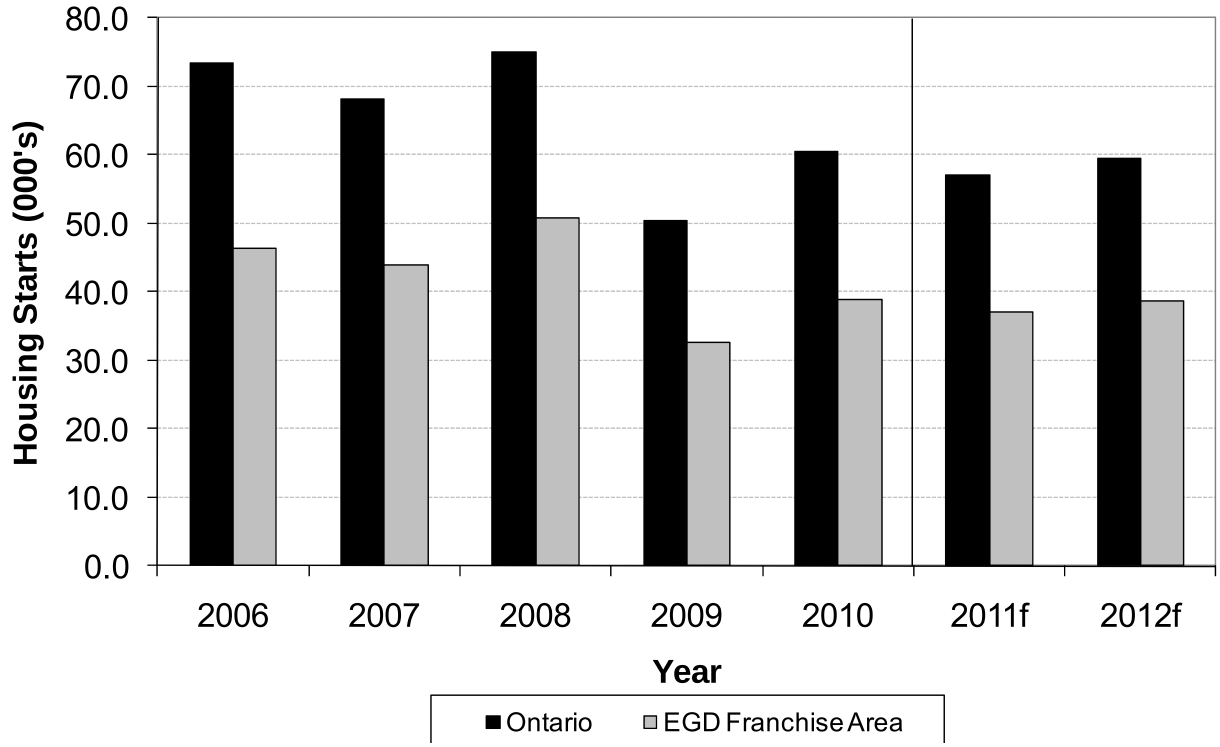
of a rising overnight rate target mortgage rates should begin to rise, albeit to rates which still remain relatively low by historical standards. Relatively low interest rates translate into comparatively low financing costs for houses and commercial structures. Consequently relatively low carrying costs should at the least maintain or put upward pressure on housing starts and business construction. Table 1 provides the Company's outlook for mortgage rates.

Housing Market

6. Housing starts in Ontario and the Company's franchise area trended down between 2004 and 2009 since reaching a peak in 2003. The increase in 2008 starts was mostly because of a surge in apartment housing starts in the Greater Toronto Area, while the rise in 2010 starts is attributed to a very weak demand from 2009, returning in 2010 following the recession. Figure 2 shows the last five years' trend in housing starts for Ontario and the Company's franchise area. Throughout this time period approximately 65% of Ontario housing starts, on average, have resided in the Company's franchise area.

7. Ontario's economy was among the leaders in driving the Canadian economic recovery during 2010 and in the first quarter of 2011. However, more moderate housing activity, and a persistently high dollar are expected to dampen the momentum in Ontario's economy for the remainder of 2011. In 2012, improved employment and economic output are expected to provide support for housing despite some downward pressure expected as a result of slightly higher interest rates. The Company expects housing starts to experience a modest decline in 2011 before increasing modestly in 2012. Table 1 shows the Company's forecast of housing starts for 2011 and 2012.

Figure 2: Housing Start Trends



8. To stem the risk of speculative buying and discouraging homeowners from taking on too much debt, the Department of Finance introduced some changes to its mortgage insurance guarantee framework. Specific amendments include: reducing the maximum amortization period from 35 years to 30 years on mortgages with a loan-to-value ratio greater than 80%, lowering the maximum Canadians can borrow to refinance their mortgages from 90% to 85%, and the withdrawal of government insurance backing on lines of credit secured by homes, such as home equity lines of credit, or HELOCs. These measures, in addition to the amendments announced in 2008 and 2010, are designed to have a stabilizing effect on the housing market.

9. The new construction market is at risk from the resale market. The ratio of resale home listings in Ontario to housing starts in Ontario has increased from 3.4 in 2003 to 6.4 in 2009 and 5.8 in 2010. Dramatic increases in the number of existing homes listed for sale has offered home buyers more options and increased competition for developers of new homes. However, average resale home prices rose 8.5% from 2009 to 2010 while new home prices rose 1.9% over the same time period. This differential in price growth rates indicates a loss in competitiveness of resale homes to new homes which will be supportive of new construction to satisfy housing demand.

Residential Customer Additions

10. Over the past five years, on average, residential customer additions constitute approximately 93% of the Company's total customer additions. Since the vast majority of total customer additions consist of residential customer additions, total customer additions will follow trends in the housing market. In addition to housing market trends, inputs from Regional Operations and builders also suggest higher customer additions forecast in 2012 compared to 2011. The Company is forecasting 35,398 residential customer additions for 2012. This forecast is comprised of 29,450 new construction customer additions and 5,948 replacement customer additions.

Apartment Customer Additions

11. During 2010 apartment starts were strong throughout the Franchise region. With the expectation of a continued economic recovery this trend is expected to continue to rise over the coming years. The Company is forecasting 59 apartment customer additions in 2012. Of this number, 49 are new construction and 10 are replacement customers.

Commercial Customer Additions

12. The economic recovery is expected to keep business investment in commercial non-residential structures consistent. The Company is currently forecasting 2,466 commercial customer additions for 2012. This forecast is comprised of 1,678 new construction and 788 replacement customer additions.

Industrial Customer Additions

13. Much like the commercial sector, the economic recovery will maintain business investment in non-residential structures for the industrial sector. The manufacturing sector in Ontario is still under pressure from a high Canadian dollar and foreign competition and will be attempting to generate as much output with as few inputs as possible. The Company is forecasting four industrial customer additions for 2012, three of which are new construction and one replacement.

14. Table 2 provides the Company's forecast of customer additions for 2012. In summary, the continued economic expansion is expected to maintain the recent momentum in the construction industry which is expected to cause customer additions to rise to a level of 37,927 in 2012. This represents an increase of 1,690 customer additions relative to the Company's 2011 Board approved customer additions forecast.

Table 2
Customer Additions

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Sector	2010 Actual	2011 Board Approved Budget	2012 Forecast
Residential			
New Construction	28,214	27,303	29,450
Replacement	6,150	6,309	5,948
Total	34,364	33,612	35,398
Apartment			
New Construction	89	30	49
Replacement	9	8	10
Total	98	38	59
Commercial			
New Construction	1,571	1,762	1,678
Replacement	868	821	788
Total	2,439	2,583	2,466
Industrial			
New Construction	4	3	3
Replacement	0	1	1
Total	4	4	4
Total Customer Additions	36,905	36,237	37,927

GAS VOLUME BUDGET

1. The purpose of this evidence is to present the 2012 Test Year forecast of volumes and related information. The evidence describes the forecasting methodology and key assumptions used to develop the 2012 volumes for General Service and Large Volume Budget. The 2012 volume budget incorporates calendar 2010 actual billing consumption for both General Service and Large Volume.

2. A summary of the volumes and customers is provided below. Further rate class detail and explanation for all gas volumes and related items are provided at Appendix A of this exhibit.

Table 1
Summary of Gas Sales and Transportation
Volumes and Customers
(Volumes in 10^6m^3)

	2010 Actual	2011 Board Approved Budget	2011 Bridge Year Estimate	2012 Budget
General Service Volumes	8 757.0	9 283.4	9 419.8	9 356.7
Contract Volumes	2 183.6	2 022.9	2 039.2	1 943.4
Total Volumes, Gas Sales and Transportation	10 940.6	11 306.3	11 459.0	11 300.1
Customers, Gas Sales and Transportation (Average)	1 926 294	1 965 538	1 957 733	1 984 734

Witness: R. Lei

3. As a consequence of the implementation of the result of Natural Gas Electricity Interface Review ("NGEIR") in 2007, the Company has experienced customer migration from bundled rate classes that have gas distribution volumes, reported in Table 1, to unbundled rate classes (e.g. Rate 125, Rate 300 Firm) that do not have distribution volumes. Unbundled customers incur monthly contract demand volumes and generate fixed contract demand revenues. Table 2 below presents a summary of these contract demand volumes.

Table 2
Summary of Unbundled Customers Contract Demand Volumes
(Volumes in 10^6m^3)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year Estimate	2012 Budget
Total Contract Demand Volumes	12.5	40.0	74.2	82.0	81.0	107.1

General Service Demand Forecast Methodology

4. The general service volumes are derived using the average use forecasting models and the customer budget. The average use models are the Company developed regression models, which are described in details in the evidence at Exhibit B, Tab 1, Schedule 7.

5. Consistent with previous rate cases, the Company continues to report the results that the models would generate using the actual data and driver variable information to allow parties to compare the results to the prior year's forecast. The average in-sample forecast error for both Rate 1 and Rate 6 regression models is still less than 1 percent on average during 2001 to 2010 as demonstrated at Exhibit B,

Witness: R. Lei

Tab 1, Schedule 7. Overall, the regression model has continued to be an excellent predictor of general service average use.

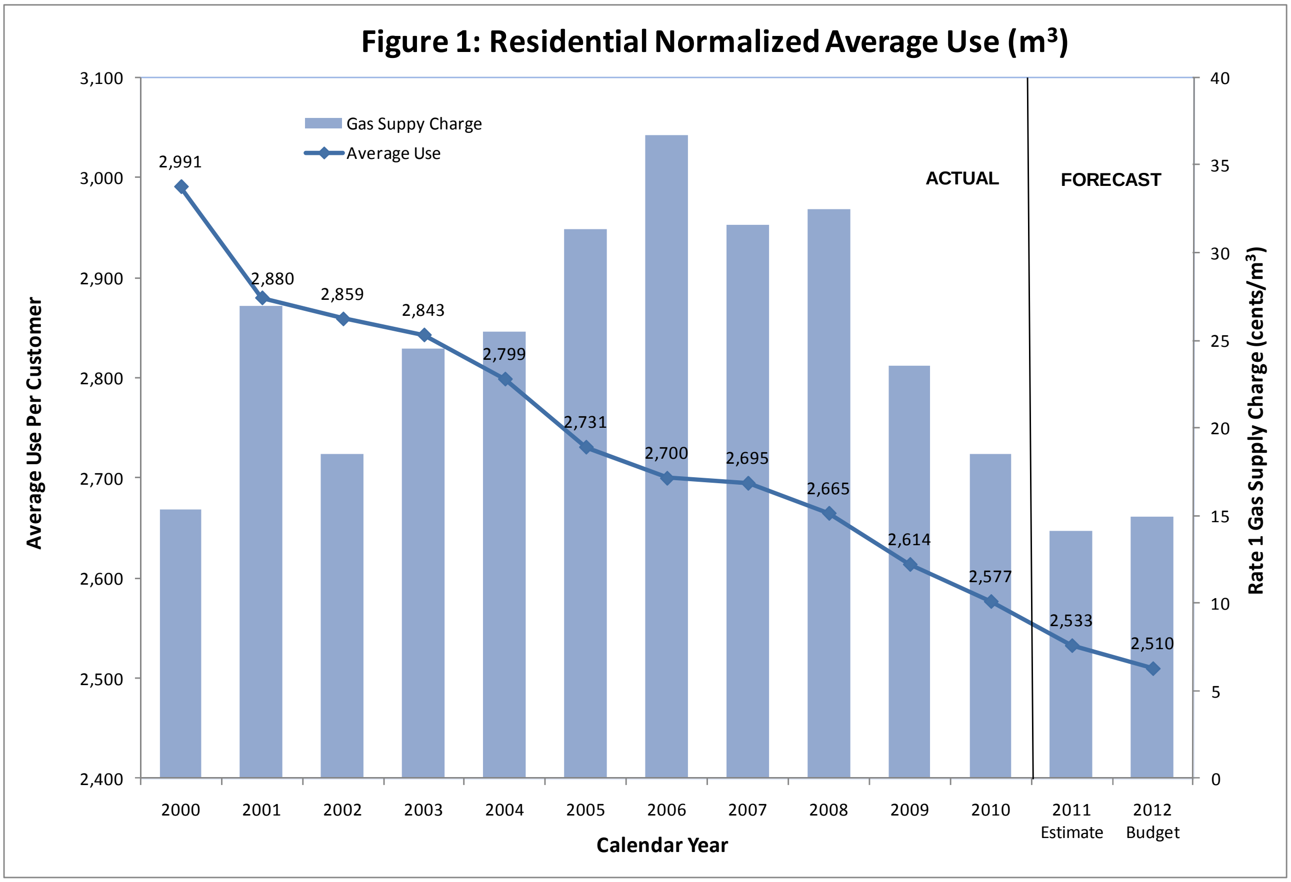
6. Annual econometric models are employed to model and quantify the impact of various driver variables on average use per customer. The forecast incorporated economic assumptions from *Economic Outlook, Spring 2011* filed at Exhibit B, Tab 1, Schedule 7. The average use regression models forecast includes 2010 actual billing consumption information.

7. The major driver variables in Rate 1 and Rate 6 models are heating degree days, vintage (Rate 1 only), employment, Ontario real gross domestic product, Ontario real gross domestic product by manufacturing industry, vacancy rates (Rate 6 only), real energy prices, and time trend. The vintage variable is constructed to reflect the impact of new homes associated with more energy efficient gas equipment over time and enhanced building codes. Gas equipment includes gas furnaces, water heaters, and stoves. The time trend, including the dynamic variable in the regression model, captures the historical actual average trend of the sectoral average use, conservation initiatives originated by customers themselves or promoted by government programs, stock turnover, and other historical impact not reflected in the mentioned driver variables. Tables of these driver variables assumptions can be found at Exhibit B, Tab 1, Schedule 7.

General Service Volumes: 2012 Budget

8. The 2012 Budget General Service volumes are 9,356.7 10^6m^3. Residential usage per customer has declined steadily over the period of 2000 through 2010. Figure 1 on the next page shows a consistent downward trend in residential average use per

customer from 2000 to the 2012 Test Year, on a weather normalized basis, as filed at Appendix A, page 15.

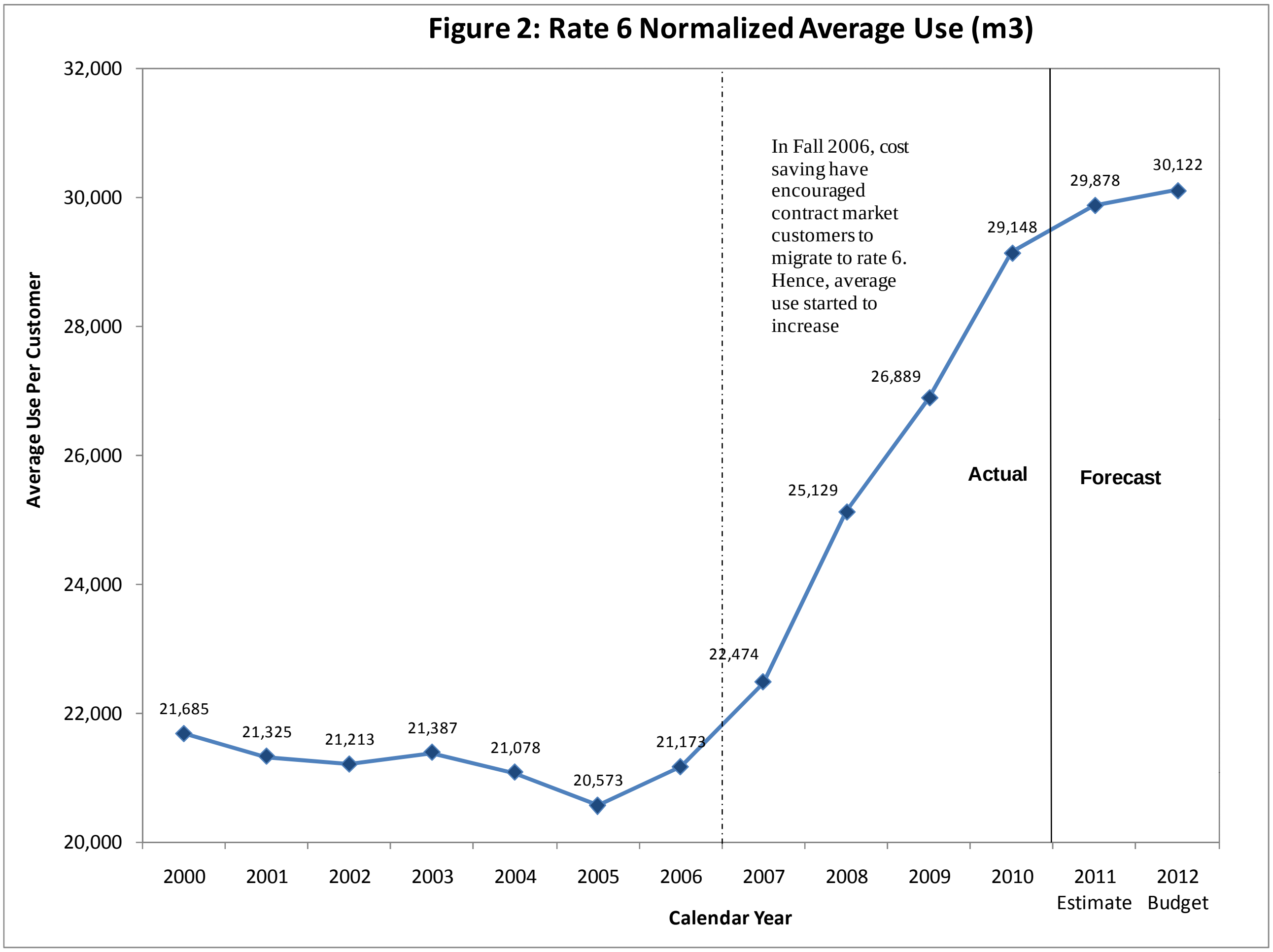


9. Residential average use is forecast to decline in 2012 due to reasons that include:
- Conservation initiatives originated by customers and also government policies and programs aimed at improving efficiencies (e.g., Green Energy Act, ecoENERGY Retrofit, Solar H2Ottawa, Ontario Home Energy Audit and Retrofit, and Ontario Solar Thermal Heating Incentive, etc);
- Replacement of older, less efficient appliances with newer high efficient units by customers;

- New homes with improved thermal envelopes based upon the historical 1997 Building Code, the new 2006 Building Code effective December 31, 2006, further changes to this 2006 Building Code effective December 31, 2008, and requiring near-full-height basement insulation effective December 31, 2009. In 2012, new houses will be required to meet standards in accordance with the national guideline, EnerGuide 80.[1]

10. Although residential average use per customer has declined by an average of 1.2% per year from 2006 to 2010, small apartment, commercial, and industrial (Rate 6) average use per customer has increased by an average of 7.2% per year during this period. The increase in actual usage is largely attributable to the rate switching from contract market customers to general service, which began in the fall of 2006. Figure 2 on the next page shows the normalized actual average use per customer for Rate 6 from 2000 to 2010, and the projection for 2011 and 2012, as filed at Appendix A, pages 15 and 16.

[1] Please refer to the Ministry of Municipal Affairs and Housing web site for further technical information, http://www.mah.gov.on.ca/Page7154.aspx.



11. From the figure above, there is a clear upward trend in usage per customer from 2006 to 2010. It is largely attributable to the customer migration from contract market to general service. Rate switching accelerated as indicated in the response to an Undertaking at EB-2006-0034, Exhibit J4.10 and 2008 Gas Volume Budget Evidence at EB-2007-0615, Exhibit C, Tab 2, Schedule 2. Rate design changes required Rates 100 and 145 to pay contract demand charges effective April 1, 2007, thus Rate 6 are more attractive to some contract market customers. It is expected that Rate 6 average use per customer will increase slightly in 2012.

Witness: R. Lei

12. Economic conditions and rate switching have always played a significant role in Rate 6 average uses. Rate 6 customers often switch between rate classes or gas service plan types if they are reasonably assured of meeting the minimum required volumes of 340,000 m^3 for requesting large volume contracts. The regression model does not predict the 2012 Budget rate switching for a heterogeneous customer mix that has a different individual usage pattern. Therefore, the impact of migration on the contract market customers in both the 2011 Estimate and the 2012 Budget are layered onto the regression model's average use forecast.

13. The average use models are the Company developed regression models, which are described in detail in the evidence at Exhibit B, Tab 1, Schedule 7. The major driver variables in Rate 1 and Rate 6 models are heating degree days, vintage (Rate 1 only), employment, Ontario real gross domestic product, Ontario real gross domestic product by manufacturing industry, vacancy rates (Rate 6 only), real energy prices, and time trend.

14. The vintage variable is constructed to reflect the impact of new homes associated with more energy efficient gas equipment over time and enhanced building codes. The time trend, including the dynamic variable in the regression model, captures the impact of conservation – both natural conservations initiated by the customers and the Company's initiatives which are not reflected in the mentioned driver variables.

15. Consistent with previous rate cases, the Company continues to report the results that the models would generate using the actual data and driver variable information to allow parties to compare the results to the prior year's forecast. The average in-sample forecast error for both Rate 1 and Rate 6 regression models is still less than 1 percent on average during 2001 to 2010 as demonstrated at Exhibit B,

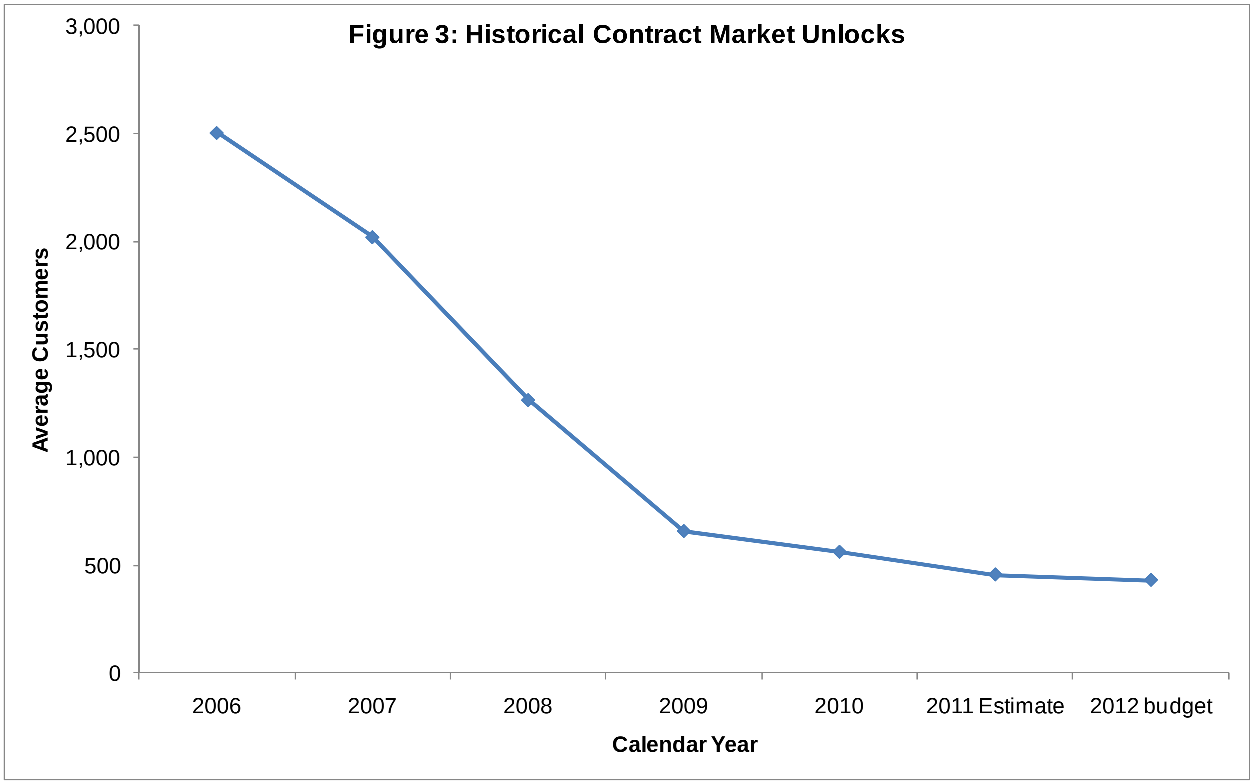
Tab 1, Schedule 7. Overall, the regression model has continued to be an excellent predictor of general service average use.

Contract Market Volume Forecast Methodology

16. The volumes in the contract market are generated using the established and approved grass roots approach. Volumes are forecast on an individual customer basis by account executives in the consultation with customers during the budget process. Specifically, the account executive reviews the contract attributes (e.g., rate and plan type) for each contract in order to ensure that the customer can meet the contracted rate class minimum volume and load factor requirements. Current economic and industry conditions, and budgeted degree days are factored into the budget determination. The 2011 Bridge Year estimate for contract market customers has also incorporated three months of 2011 actual information.

17. As mentioned in the previous section, changes in the rate design that were accepted in the IR Settlement Agreement in EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, pages 33 and 34, have reduced the cost difference between general service and contract rate classes for contract customers. Specifically, these rate design changes require Rates 100 and 145 customers to pay contract demand charges. Consequently, these customers may benefit by migrating to Rate 6. These changes helped to increase the rate switching trend experienced during the years 2006 to 2010.

18. The following Figure 3 shows the declining trend of historical actual contract market unlocks between 2006 and 2010 and the projection for 2011 and 2012.



19. As the above graph illustrates, there are approximately 1,500 contract market customers that have migrated to general service over the period 2006 through 2010. This customer migration has directly driven up the average use per customer in Rate 6 as shown in Figure 2.

<u>Comparison of 2012 Budget and 2011 Estimate - Summary</u>

20. The 2012 Budget volumes reflect the meter reading heating degree days forecast for the Central Region of 3,532, a decrease of 70 degree days compared to the 2011 Board Approved level of 3,602. Meter reading heating degree days are determined by amalgamating Gas Supply heating degree days with the billing schedules. Evidence related to the forecast of Gas Supply heating degree days is presented at Exhibit B, Tab 1, Schedule 6.

21. The 2012 Budget volumes of 11 300.1 10^6m^3 are forecast to be 158.9 10^6m^3 or 1.4% below the 2011 Bridge Year Estimate of 11 459.0 10^6m^3. This decrease is primarily attributable to the lower degree days forecast mentioned above and other factors discussed below. On a weather-normalized basis, the 2012 Budget volumes are forecast to be 16.3 10^6m^3 below the 2011 Bridge Year Estimate. The decrease on a normalized basis is made up of a decrease in the contract market of 88.5 10^6m^3, which is partially offset by an increase in general service volumes of 72.2 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 1 to 6.

22. The increase in the general service volumes of 72.2 10^6m^3 on a weather-normalized basis is primarily due to net customer growth of 78.5 10^6m^3 and rate switching from contract rate to a general service (or transfer gains) of 25.4 10^6m^3. The customer growth mitigates the lower average use per customer of 32.5 10^6m^3. Efficiency improvements are assumed to be the primary driver of the decline in residential average use per customer. These would include government policies and initiatives aimed at improving efficiencies and improved building envelopes. More recently, economic conditions are also likely having an impact, and perhaps even reinforcing conservation activities.

23. Table 3 on the next page quantifies the volumetric impact of the average use driver variables on residential sector's average use forecast and customer growth respectively. On a weather-normalized basis, the increase in the residential volumes of 25.0 10^6m^3 is a result of customer growth, partially offset by the ongoing average use decline as shown in Figure 1.

Table 3

Factors Influencing the Changes in Residential Gas Consumption

Between 2012 Test Year Budget and 2011 Bridge Year Estimate (10^6m^3)

Factors	**Total Volume (10^6m^3)**	
Customer Growth	65.5	
DSM Initiatives	(10.0)	
New Homes - historical trend (a)	(20.2)	
Gas Prices	(10.3)	
Other Conservation (b)	0.0	*
Gas Appliances (c)	0.0	
Total	25.0	

(a) Measured by vintage variable, reflecting the historical impacts of improved building envelopes for new homes along with more efficient new space heating furnaces and water heaters on average uses based upon both historical building code, the new 2006 Building Code for new homes effective December 31, 2006. Further changes to this 2006 Building Code effective December 31, 2008, require near-full-height basement insulation effective December 31, 2009.

(b) Other Conservation includes the expected ongoing technology improvements of furnaces and more energy efficient gas-fired storage water heaters for existing homes, and conservation initiatives originated by customers themselves or promoted by government programs, such as programmable thermostats, low-flow showerheads, and home renovations, other historical impact not reflected in the mentioned driver variables, etc.

(c) Measured by employment variable to reflect the demand for gas appliances or gas technologies.

* Less than 50,000 m^3

24. Table 4 on the next page illustrates the volumetric impact of the average use driver variables on the apartment, commercial, and industrial sector's average use forecast and customer growth, respectively. On a weather-normalized basis, the

increase in Rate 6 volumes of 46.6 10^6m^3 is primarily due to rate switching from contract rate to a general service of 25.4 10^6m^3 and customer growth of 13.2 10^6m^3.

Table 4

Factors Influencing the Changes in Rate 6 Gas Consumption

Between 2012 Test Year Budget and 2011 Bridge Year Estimate (10^6m^3)

Factors	**Apartment (10^6m^3)**	**Commercial (10^6m^3)**	**Industrial (10^6m^3)**	**Total Volume (10^6m^3)**
Customer Growth	2.1	10.9	0.2	13.2
DSM Initiatives	(10.9)	(12.8)	(2.6)	(26.3)
Economics, Gas Appliances (a)	21.7	3.6	19.5	44.8
Rate Switching - change in rate design (b)	11.5	7.1	6.8	25.4
Other Conservation (c)	(4.7)	(0.2)	(0.4)	(5.3)
Gas Prices	(4.9)	0.0	(0.2)	(5.1)
Total	14.7	8.6	23.3	46.6

(a) Measured by economic variables as explained at Exhibit B, Tab 1, Schedule 7, to reflect
the demand for gas appliances or gas technologies, to capture the historical actual
average trend of the rate 6 average use, such as transfer gains/losses
impact on average uses, vacancy rate, etc

(b) Incremental impact of rate switching as a result of change in rate design that was accepted in
the Incentive Regulation Settlement Agreement at EB-2007-0615, Exhibit N1, Tab 1,
Schedule 1, Pages 33-34 which will not be captured from the historical business trend
as mentioned in (a) above.

(c) Other Conservation includes the expected ongoing technology improvements of furnaces,
and conservation initiatives originated by customers themselves or promoted by
government programs, such as programmable thermostats, improved building envelopes,
low-flow showerheads, and building renovations, other historical impact not reflected
in the mentioned driver variables, construction trend, changes to building code, etc.

25. The 2012 large volume budget is expected to have a moderate decline of 88.5 10^6m^3 compared to 2011 Estimate on a weather-normalized basis. The underage is mainly caused by customer migration to general service (or transfer losses) of 25.4 10^6m^3. After removing the unfavourable rate switching volumetric impact, the 2012 contract market volume budget is expected to be 63.1 10^6m^3 lower than the 2011 Estimate on a weather normalized basis. With some of the contract market customers being heavily dependant on the U.S. economy, along with the strong Canadian dollar, the decline in volumetric demand was anticipated. The following Table 5 illustrates major variance drivers contributing to the reduction in contract market volumes between 2012 Budget and 2011 Estimate. Table 6 on page 14, illustrates migration to Rate 6 by trade group.

Table 5 - Comparison of Contract Market Volumes
2012 Budget and 2011 Bridge Year Estimate
(10^6m^3)

	Col. 1	Col. 2	Col. 3
	2012 Budget	2011 Bridge Year Estimate	2012 Budget Over (Under) 2011 Estimate
			(1-2)
Contract Market Total Gas Sales and Transportation Volumes	1,943.4	2,039.2	(95.8)
Major Variance Factors:			
Weather Normalization, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 4, Col. 4, Item No. 4			(7.3)
Lost customers			(1.2)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			0.9
Transfer losses - net migration of customers from contract rates to general service rate 6			(26.3)
Wholesale customer			0.1
Pulp and Paper Industry			(20.6)
Impact of price spread between Hydro and Gas on Distributed Energy customers			(15.1)
Refined Petroleum Industry			(14.8)
Chemical and Chemical Products Industry			(2.9)
Impact of contruction projects of one Education Service customer			(2.7)
Others change in usage (e.g. change in production process, etc.)			(5.8)
Total Major Variance Factors:			**(95.8)**

Table 6 - Customer Migration from Contract Rate to Rate 6
Between 2012 Budget and 2011 Bridge Year Estimate

1. Customers that migrating to Rate 6 in 2011

	Number of Customers*	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	(34)	Apartment	(9.5)
	(1)	Business & Financial Service Industries	(2.5)
	(3)	Chemical and Chemical Products	(0.5)
	(1)	Education Services	(0.8)
	(2)	Food, Beverage, Drug & Tobacco	(0.6)
	(2)	Government Services	(1.0)
	(5)	Greenhouses/Agriculture	(2.5)
	(1)	Health, Social & Other Services	(0.2)
	(1)	Hotels	(0.2)
	(1)	Non-Metallic Mineral Products	(0.3)
	(2)	Primary Metal & Machinery	(1.0)
	(2)	Pulp & Paper	(1.0)
	(1)	Refined Petroleum	(0.5)
	(2)	Transportation and Storage and Utilities	(1.1)
	(1)	Transportation Equipment	(1.2)
	(1)	Wholesale & Retail Trade	(0.8)
Total	(60)		(23.7)

2. Customers that will be migrated to Rate 6 in 2012

	Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	(2)	Apartment	(2.0)
	(1)	Business & Financial Service Industries	(0.6)
Total	(3)		(2.6)
Grand Total	**(63)**		**(26.3)**

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

Witness: R. Lei

Comparison of 2011 Estimate and 2011 Board Approved Budget

26. The Estimate volumes of the 11 459.0 10^6m^3 are forecast to be 152.7 10^6m^3 or 1.4% above the 2011 Board Approved Budget of 11 306.3 10^6m^3. The increase on a normalized basis is made up of increases in general service volumes of 136.4 10^6m^3 and in the contract market of 16.3 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 8 to 10.

27. The increase in the general service volumes of 136.4 10^6m^3 is primarily due to net rate switching gains from contract rate class to a general service rate class (or transfer gains) of 33.0 10^6m^3 mainly due to migration and higher Rate 6 average use of 303.0 10^6m^3. It is partially offset by lower residential average use of 126.6 10^6m^3 and customer losses of 73.0 10^6m^3. Customer losses are primarily driven by plant closures or relocations of Rate 6 customers from commercial and industrial sectors. Residential average use per customer in the 2011 Estimate was forecast to be 70.0 m^3 or 2.7% lower compared to 2011 Budget. It is highly influenced by customers who implemented energy efficiency efforts, more specifically the replacement of older, less efficient appliances with high efficient units or improvements on home insulation and windows.

28. The modest increase in the large volume of 16.3 10^6m^3 is primarily due to improvement in market conditions during 2011, which is offset by customer migration to general service. Table 7 on the next page, shows major variance drivers contributing to these variances by trade group. Tables 8 and 9 on pages 17 to 18, present rate switching between contract market and general service.

Table 7 - Comparison of Contract Market Volumes
2011 Bridge Year Estimate and 2011 Board Approved Budget
($10^6 m^3$)

	Col. 1	Col. 2	Col. 3
	2011 Bridge Year Estimate	2011 Budget	2011 Estimate Over (Under) 2011 Budget (1-2)
Contract Market Total Gas Sales and Transportation Volumes	2,039.2	2,022.9	16.3
Major Variance Factors:			
Weather Normalization, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 4, Col. 4, Item No. 4			0.0
Lost customers			(7.1)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			38.8
Transfer losses - migration of customers from contract rates to general service rate 6			(71.8)
Wholesale customer			8.4
Distributed Energy customers			23.6
Refined Petroleum Industry			20.3
Chemical and Chemical Products Industry			6.0
Non-Metallic Mineral Products Industry			(3.1)
Others change in usage (e.g. change in production process, etc.)			1.2
Total Major Variance Factors:			**16.3**

Table 8 - Customer Migration from Contract Rate to Rate 6
Between 2011 Bridge Year Estimate and 2011 Board Approved Budget

1. Customers that already migrated to Rate 6 in 2011

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(53)	Apartment	(32.3)
	(1)	Business & Financial Service Industries	(1.2)
	(3)	Chemical and Chemical Products	(1.6)
	(3)	Electronics/High Tech	(13.3)
	(4)	Food, Beverage, Drug & Tobacco	(4.2)
	(2)	Government Services	(1.4)
	(6)	Greenhouses/Agriculture	(1.8)
	(1)	Health, Social & Other Services	(0.2)
	(1)	Hotels	(0.9)
	(1)	Non-Metallic Mineral Products	(0.4)
	(3)	Primary Metal & Machinery	(7.2)
	(2)	Pulp & Paper	(1.7)
	(1)	Refined Petroleum	(1.8)
	(2)	Transportation and Storage and Utilities	(0.7)
	(2)	Wholesale & Retail Trade	(2.3)
Total	(85)		(71.0)

2. Customers that will be migrated to Rate 6 in Fall 2011

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(5)	Apartment	(0.6)
	(1)	Primary Metal & Machinery	(0.2)
Total	(6)		(0.8)
Grand Total	**(91)**		**(71.8)**

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

Witness: R. Lei

Table 9 - Customer Migration from Rate 6 to Contract Rate
Between 2011 Bridge Year Estimate and 2011 Board Approved Budget

1. Customers that migrate to Rate 6 in 2011

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	17	Apartment	5.7
	1	Education Services	0.8
	1	Transportation Equipment	1.2
Total	19		7.7

2. Customers that will be migrated to Rate 6 in 2011

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	1	Apartment	0.6
	1	Business & Financial Service Industries	0.6
Total	2		1.2

3. Customers stayed at contract due to improved market conditions

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	5	Asphalt	4.9
	7	Food, Beverage, Drug & Tobacco	8.6
	1	Other Utility Industries (Cogen)	4.5
	3	Primary Metal & Machinery	3.6
	3	Pulp & Paper	5.9
	1	Rubber Products	2.4
Total	20		29.9
Grand Total	**41**		**38.8**

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

Comparison of 2011 Estimate and 2010 Actual

29. The Estimate volumes of the 11 459.0 10^6m^3 reflect the meter reading heating degree days forecast of 3,602 in the Central Region, an increase of 136 degree days compared to the 2010 Actual of 3,466. The colder weather forecasted is the main reason of the volume demand increase of 518.4 10^6m^3 or 4.7% above the 2010 Actual of 10 490.0 10^6m^3. On a weather-normalized basis the 2011 Bridge Year Estimate volumes are 78.5 10^6m^3 or 0.7% above the 2010 Actual. The increase on a normalized basis is made up of an increase in general service volumes of 229.9 10^6m^3 and a decrease in the contract market of 151.4 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 11 to 14.

30. The normalized volume increase in the general service of 229.9 10^6m^3 is primarily due to customer growth of 182.7 10^6m^3 and customer migration from the contract market of 62.2 10^6m^3. It is partially offset by a moderate decline in average use per customer of 15.0 10^6m^3. As illustrated in Figure 1, residential normalized average use in 2011 is projected to decline by 44 m^3 per customer, which is mainly driven by efficiency improvements. However, Rate 6 average use per customer has been steadily increasing since 2006. Particularly in 2011, usage per customer in Rate 6 is projected to increase by 730.0 m^3 or 2.5% compared to 2010, which results in an increase in total volumetric demand in general service for 2011.

31. The decrease in the contract market volumes of 151.4 10^6m^3 on a weather-normalized basis is primarily due to rate switching from a contract rate to general service (or transfer losses) of 62.2 10^6m^3 as mentioned above. Absent rate switching, the 2011 contract market volumes are projected to be 89.2 10^6m^3 below 2010 actual. Table 10 on the next page, illustrates major drivers contributing to

these variances by trade group. Table 11 on page 21, presents customer migration to Rate 6 by trade group.

Table 10 - Comparison of Contract Market Volumes
2011 Bridge Year Estimate and 2010 Actual
(10^6m^3)

	Col. 1	Col. 2	Col. 3
	2011 Bridge Year Estimate	2010 Actual	2011 Estimate Over (Under) 2010 Actual
			(1-2)
Contract Market Total Gas Sales and Transportation Volumes	2,039.2	2,183.6	(144.4)
Major Variance Factors:			
Weather Normalization, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 4, Col. 4, Item No. 4			7.0
Lost customers			(5.5)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			16.0
Transfer losses - migration of customers from contract rates to general service rate 6			(78.2)
Wholesale customer			(7.5)
Pulp & Paper Industry			(36.0)
Primary Metal & Machinery Industry			(12.4)
Transportation Equipment Industry and Asphalt Industry			(9.6)
Chemical and Chemical Products Industry			(7.5)
Non-Metallic Mineral Products Industry			(10.3)
Others change in usage (e.g. change in production process, etc.)			(0.4)
Total Major Variance Factors:			**(144.4)**

Table 11 - Customer Migration from Contract Rate to Rate 6
Between 2011 Bridge Year Estimate and 2010 Actual

	Number of Customers*	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	(87)	Apartment	(38.1)
	(2)	Business & Financial Service Industries	(1.3)
	(5)	Chemical and Chemical Products	(1.2)
	(1)	Construction Industries	(0.9)
	(2)	Education Services	(1.0)
	(2)	Electronics/High Tech	(4.1)
	(5)	Food, Beverage, Drug & Tobacco	(4.4)
	(2)	Government Services	(0.9)
	(7)	Greenhouses/Agriculture	(1.6)
	(1)	Health, Social & Other Services	(0.1)
	(2)	Hotels	(0.9)
	(1)	Non-Metallic Mineral Products	(0.4)
	(5)	Primary Metal & Machinery	(7.7)
	(3)	Pulp & Paper	(1.7)
	(1)	Refined Petroleum	(1.6)
	(3)	Rubber Products	(1.4)
	(1)	Textile Products	(0.8)
	(3)	Transportation and Storage and Utilities	(0.6)
	(3)	Transportation Equipment	(6.2)
	(5)	Wholesale & Retail Trade	(2.4)
	(1)	Wood & Furniture Industries	(0.9)
Total	(142)		(78.2)

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

Evaluation of Forecast Accuracy – Historical Normalized Actual vs. Board Approved Budget

32. As historical Board Approved volumes for the periods prior to 2006 were developed and approved based upon fiscal year information (i.e., September 30 fiscal year

end), the information for periods prior to 2006 shown in this section are presented on a fiscal-year basis whereas year 2006 and beyond are presented on a calendar-year basis.

33. The key factors to evaluate forecast accuracy of volume demand in general service is to assess the normalized variance of residential average use per customer. Appendix A, page 18 illustrates 10-Year of Normalized Actual vs. Board Approved volumes. The average normalized percentage error variances between 2001 and 2010 were less than 1.0% for Rate 1 average use per customer. Hence, the methodology that is consistent with the approach taken in prior years continues to be a reasonable predictor for general service average use.

34. As for the contract market, migration has had a significant impact since 2006. Appendix A, page 20 illustrates 10-Year of Normalized Actual vs. Board Approved volumes for contract market customers to evaluate the accuracy of forecast volumes.

Weather Normalization Methodology

35. The Company's weather normalization methodology has been approved by the Board and utilized for more than ten years. Consistent with previous rate cases, this section explains the Board approved normalization methodology of normalizing actual consumption for general service rate classes.

36. General Service normalization is carried out taking customers at a group level. The Company's General Service customers are grouped together into homogenous classes of gas usage within the three delivery areas (and six operating regions) of the Company's franchise area. Only the heat sensitive portion of consumption is

normalized for heat sensitive or balance point degree days. Further explanation of the balance point degree days is explained later.

37. Firstly, the total load per customer of a customer group is calculated by dividing the group's consumption by the total customers within this group. Then, baseload per customer is calculated by taking an average of the two non-weather sensitive summer months' total load. Baseload represents non-weather sensitive load, such as water heating and other non-heating uses. Thereafter, heatload per customer is calculated by subtracting the baseload per customer from the total load per customer. This heatload represents the heat sensitive portion of consumption. By dividing the heatload per customer by Actual Heating Degree Days, an Actual Use per Degree Day is generated. The Actual Use per Degree Day is then adjusted to reflect normal weather by multiplying the Budget Heating Degree Days. Consequently, total normalized average use per customer is defined as an aggregate sum of baseload use per customer and normalized heatload per customer.

38. In EBRO 487, the Company proposed to change from the traditional 18^{O}C balance point temperature assumption to a new temperature for purposes of normalizing average general service customer uses. This new normalizing technique has been beneficial in reducing the volatility in residential normalized average use for the shoulder months of November and April and, to a lesser extent, October and May. Shoulder months have been important in the overall consideration of average use trends. Unnormalized average uses in the months leading into the winter period can fluctuate significantly depending on the length of a warm or cold cycle.

39. For contract market customers who consume more than 340,000 m^3 annually, a similar process is followed to determine the actual baseload for each contract. Actual heatload is obtained by removing the baseload and the process load from the total consumption, which is then adjusted to reflect normal weather. The actual volumes are also adjusted, where necessary, to the budgeted level of curtailment.

AVERAGE NUMBER OF CUSTOMERS

1. The purpose of this exhibit is to present the calculation of the 2012 annual average customers reported in the 2012 Revenue per Customer Cap formula at Exhibit B, Tab 1, Schedule 2. The annual average customer methodology used by the Company has been applied to calculate Board Approved annual average customer for more than ten years. All the information shown in this evidence is on a calendar-year billing-period basis (i.e., on a December fiscal year end basis) excluding the time periods prior to 2006 in the Historical Actual vs. Board Approved section. The Test Year Budget includes calendar 2010 Actual and 2011 Bridge Year Estimate billing information.

2. The 2012 Customers Budget of 1,984,734 is forecast to be 27,001 or 1.4% above the 2011 Bridge Year Estimate of 1,957,733. The increase in customers is primarily attributable to the customer additions in the 2012 Budget. The total customer additions for the 2012 Budget are 37,927, which are described in detail in the evidence at Exhibit B, Tab 1, Schedule 4. The customer additions forecast underpins the new customer volumes of 65.5 $10^6 m^3$ added between 2012 Budget and 2011 Estimate at Exhibit B, Tab 1, Schedule 5, page 5. The 2011 Bridge Year Estimate Customers Budget of 1,957,733 is 7,805 lower than the 2011 Board Approved Budget.

3. Consistent with previous rate proceedings, each year's customer numbers are reported on an annual average of monthly customer numbers. Every month customer numbers are measured by number of active meters (or unlock meters)[1].

[1] Unlock meter is defined as customer whose gas meter is unlocked, allowing gas to flow through the meter to a premise.

Witness: R. Lei

As a result, each month's customer number is an aggregate sum of the total active meters for that particular month. Specifically, each year's annual average is calculated as follows:

annual average_customer = (1/12)(january_customer + february_customer + march_customer + april_customer + may_customer + june_customer + july_customer + august_customer + september_customer + october_customer + november_customer + december_customer)*

4. Consistent with the contract demand forecast methodology discussed in the Gas Volume Budget Evidence at Exhibit B, Tab 1, Schedule 5, contract customer counts in the contract market are generated through an approved grass root approach between account executives and customers. The formula for forecasting the total number of contract market customers is as follows:

forecast contract market customers = year end customers (2011 Estimate)
+ forecast new customer additions
+ forecast replacement customer additions
- forecast lost customers
+ forecast transfer gains (i.e. customer migration from general service Rate 6 to contract market rate class)
– forecast transfer losses (i.e. customer migration from contract market rate class to general service Rate 6)

5. The forecast of total number of general service customers is obtained by adding the forecast customer additions at Exhibit B, Tab 1, Schedule 4 along with a time lag between customer additions and unlock meters to the number of customers

recorded at the end of the bridge year estimate. Historical average monthly change in actual lock meters or customers are then added to these numbers. Transfer gains or losses between contract rate class and general service Rate 6 obtained from account executives are then layered onto general service Rate 6 customers. The formula for forecasting the total number of general service customers is as follows:

forecast general service customers = year end customers (2011 Estimate)
*+ forecast new construction customer additions*new construction time lag*
*+ forecast replacement customer additions*replacement time lag*
+ historical average monthly change in actual lock customers
+ forecast transfer gains (i.e. customer migration from contract market rate class to general service Rate 6)
- forecast transfer losses (i.e. customer migration from general service Rate 6 to contract market rate class)

6. Lock meters are defined as customers whose gas meters are locked and no gas is flowing through the meter to a premise. These can result from vacant premises (e.g. new construction, move-in/move out, bankruptcies, etc.), customers switching off gas to an alternate energy source, payment or credit reasons and seasonal usage. The Company has experienced an increase in lock meters, which has resulted in lower net customer growth. Unfavourable economic conditions, e.g. vacancy or bankruptcy, may lead to an increase in lock meters and this factor has been incorporated into the customer forecast. Table 1 below presents the past three years historical annual actual lock customer data.

Table 1 - Historical Annual Average Locks Customers

Calendar Year	Lock Customers
2008	33,055
2009	35,044
2010	40,518

7. There is always a lag time between when the service line is installed (that underpins capital expenditures and customer additions) and the flow of gas. When the customer moves into the premise and calls to have meter unlocked by field staff, gas service and customer's account (that underpins billed revenues and volumes) will be activated. This time lag is incorporated into the customer number calculation.

8. Similar to lock customers, this time lag is challenging to predict. Therefore, the latest available historical actual data is used in order to obtain an objective forecast of lock meters for the budget. Table 2 on the following page, presents a summary of the 2012 budgeted time lag. It is expected that the average time lag (i.e., number of months) for replacement customer additions will be shorter than for new construction or subdivision customer additions. Also, the average time lag for commercial buildings or offices is anticipated to be longer than residential homes.

Table 2 - 2012 Budget Time Lag (i.e. Number of Months)

Sector	New Construction	Replacement
Residential	6	3
Apartment	7	7
Commercial	12	11
Industrial	7	7

Evaluation of Forecast Accuracy – Historical Actual vs. Board Approved Budget

9. As historical Board Approved customer numbers for the periods prior to 2006 were developed and approved based upon fiscal year information (i.e., September 30 fiscal year end), the information for periods prior to 2006 shown in this section are presented on a fiscal-year basis whereas year 2006 and beyond are presented on a calendar-year basis.

10. Table 3 on the following page, illustrates 16-Year of Historical Actual vs. Board Approved customer numbers and the projection for 2011 and 2012. Overall, the average percentage error variances over the past 16 years were 1,301 customers or less than 0.1%. Overall, the existing methodology has continued to be a good predictor of actual customers.

TABLE 3 - GENERAL SERVICE AND CONTRACT MARKET CUSTOMERS

	Test Year	Col. 1 Actual Customers	Col. 2 Board Approved Customers	Col. 3 Variance Customers (1-2)	Col. 4 %Variance Customers (3/2)*100
FISCAL YEAR	1995	1,222,293	1,216,511	5,782	0.5%
	1996	1,263,290	1,262,815	475	0.0%
	1997	1,312,434	1,309,752	2,682	0.2%
	1998	1,364,350	1,353,178	11,172	0.8%
	1999	1,414,788	1,417,832	(3,044)	-0.2%
	2000[a]	1,464,738	1,468,915	(4,177)	-0.3%
	2001	1,519,039	1,514,710	4,329	0.3%
	2002	1,566,710	1,565,017	1,693	0.1%
	2003	1,622,016	1,615,037	6,979	0.4%
	2004*	1,676,380	1,672,586	3,794	0.2%
	2005[b]	1,724,716	1,718,766	5,950	0.3%
CALENDAR YEAR	2006	1,782,813	1,792,615	(9,802)	-0.5%
	2007	1,824,789	1,823,258	1,531	0.1%
	2008	1,865,020	1,864,047	973	0.1%
	2009	1,887,605	1,906,437	(18,832)	-1.0%
	2010	1,926,294	1,931,528	(5,234)	-0.3%
	2011**	1,957,733	1,965,538	(7,805)	-0.4%
	2012		1,984,734		

* 2004 Bridge Year Estimate from RP-2003-0203 was reported at column 2 because Board Approved numbers are not available since there was no 2004 Board Approved Volumes Budget due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

**2011 Bridge Year Estimate was reported at column 1 because actual numbers are not available

a. In consequence of the ADR settlement agreement in capital expenditure, there was a reduction in customers of 2,251 to the board approved budget numbers.

b. In consequence of the ADR settlement agreement in capital expenditure, there was a reduction in customers of 1,022 to the board approved budget numbers.

Witness: R. Lei

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2012 BUDGET

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	
General Service				
1.1.1	Rate 1 - Sales	1 467 726	3 693.2	
1.1.2	Rate 1 - T-Service	359 070	890.1	
1.1	Total Rate 1	1 826 796	4 583.3	
1.2.1	Rate 6 - Sales	127 809	2 620.6	
1.2.2	Rate 6 - T-Service	29 691	2 151.6	
1.2	Total Rate 6	157 500	4 772.2	
1.3.1	Rate 9 - Sales	8	1.0	
1.3.2	Rate 9 - T-Service	1	0.2	
1.3	Total Rate 9	9	1.2	
1.	Total General Service Sales & T-Service	1 984 305	9 356.7	
Contract Sales				
2.1	Rate 100	0	0.0	
2.2	Rate 110	34	64.3	
2.3	Rate 115	0	0.0	
2.4	Rate 135	1	0.6	
2.5	Rate 145	11	21.4	
2.6	Rate 170	5	49.7	
2.7	Rate 200	1	162.2	
2.	Total Contract Sales	52	298.2	
Contract T-Service				
3.1	Rate 100	0	0.0	
3.2	Rate 110	167	423.8	
3.3	Rate 115	30	532.5	
3.4	Rate 125	5	0.0	*
3.5	Rate 135	37	54.6	
3.6	Rate 145	97	133.0	
3.7	Rate 170	33	470.3	
3.8	Rate 300	8	31.0	
3.9	Rate 315	0	0.0	
3.	Total Contract T-Service	377	1 645.2	
4.	Total Contract Sales & T-Service	429	1 943.4	
5.	Total	1 984 734	11 300.1	

* There is no distribution volume for Rate 125 customers.

Witness: R. Lei

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2012 BUDGET AND 2011 BRIDGE YEAR ESTIMATE

Item No.		Col. 1 2012 Budget	Col. 2 2011 Bridge Year Estimate	Col. 3 2012 Budget Over (Under) 2011 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 467 726	1 394 781	72 945
1.1.2	Rate 1 - T-Service	359 070	405 147	(46 077)
1.1	Total Rate 1	1 826 796	1 799 928	26 868
1.2.1	Rate 6 - Sales	127 809	123 260	4 549
1.2.2	Rate 6 - T-Service	29 691	34 080	(4 389)
1.2	Total Rate 6	157 500	157 340	160
1.3.1	Rate 9 - Sales	8	10	(2)
1.3.2	Rate 9 - T-Service	1	1	0
1.3	Total Rate 9	9	11	(2)
1.	Total General Service Sales & T-Service	1 984 305	1 957 279	27 026
Contract Sales				
2.1	Rate 100	0	3	(3)
2.2	Rate 110	34	35	(1)
2.3	Rate 115	0	0	0
2.4	Rate 135	1	1	0
2.5	Rate 145	11	11	0
2.6	Rate 170	5	5	0
2.7	Rate 200	1	1	0
2.	Total Contract Sales	52	56	(4)
Contract T-Service				
3.1	Rate 100	0	7	(7)
3.2	Rate 110	167	170	(3)
3.3	Rate 115	30	30	0
3.4	Rate 125	5	4	1
3.5	Rate 135	37	37	0
3.6	Rate 145	97	109	(12)
3.7	Rate 170	33	33	0
3.8	Rate 300	8	8	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	377	398	(21)
4.	Total Contract Sales & T-Service	429	454	(25)
5.	Total	1 984 734	1 957 733	27 001

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2012 BUDGET AND 2011 BRIDGE YEAR ESTIMATE
(10^6m^3)

Item No.		Col. 1 2012 Budget	Col. 2 2011 Bridge Year Estimate	Col. 3 2012 Budget Over (Under) 2011 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 693.2	3 595.4	97.8
1.1.2	Rate 1 - T-Service	890.1	1 033.7	(143.6)
1.1	Total Rate 1	4 583.3	4 629.1	(45.8)
1.2.1	Rate 6 - Sales	2 620.6	2 460.2	160.4
1.2.2	Rate 6 - T-Service	2 151.6	2 329.9	(178.3)
1.2	Total Rate 6	4 772.2	4 790.1	(17.9)
1.3.1	Rate 9 - Sales	1.0	0.4	0.6
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0
1.3	Total Rate 9	1.2	0.6	0.6
1.	Total General Service Sales & T-Service	9 356.7	9 419.8	(63.1)
Contract Sales				
2.1	Rate 100	0.0	1.6	(1.6)
2.2	Rate 110	64.3	59.5	4.8
2.3	Rate 115	0.0	0.0	0.0
2.4	Rate 135	0.6	0.6	0.0
2.5	Rate 145	21.4	23.9	(2.5)
2.6	Rate 170	49.7	52.1	(2.4)
2.7	Rate 200	162.2	165.8	(3.6)
2.	Total Contract Sales	298.2	303.5	(5.3)
Contract T-Service				
3.1	Rate 100	0.0	6.4	(6.4)
3.2	Rate 110	423.8	429.1	(5.3)
3.3	Rate 115	532.5	548.7	(16.2)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	54.6	54.6	0.0
3.6	Rate 145	133.0	159.0	(26.0)
3.7	Rate 170	470.3	506.9	(36.6)
3.8	Rate 300	31.0	31.0	0.0
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 645.2	1 735.7	(90.5)
4.	Total Contract Sales & T-Service	1 943.4	2 039.2	(95.8)
5.	Total	11 300.1	11 459.0	(158.9)

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2012 BUDGET AND 2011 BRIDGE YEAR ESTIMATE
(10^6m^3)

Item No.		Col. 1 2012 Budget	Col. 2 2011 Bridge Year Estimate	Col. 3 2012 Budget Over (Under) 2011 Estimate (1-2)	Col. 4 2011* Adjustments	Col. 5 2012 Budget Over (Under) 2011 Estimate with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 693.2	3 595.4	97.8	(55.7)	153.5
1.1.2	Rate 1 - T-Service	890.1	1 033.7	(143.6)	(15.1)	(128.5)
1.1	Total Rate 1	4 583.3	4 629.1	(45.8)	(70.8)	25.0
1.2.1	Rate 6 - Sales	2 620.6	2 460.2	160.4	(32.8)	193.2
1.2.2	Rate 6 - T-Service	2 151.6	2 329.9	(178.3)	(31.7)	(146.6)
1.2	Total Rate 6	4 772.2	4 790.1	(17.9)	(64.5)	46.6
1.3.1	Rate 9 - Sales	1.0	0.4	0.6	0.0	0.6
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0	0.0	0.0
1.3	Total Rate 9	1.2	0.6	0.6	0.0	0.6
1.	Total General Service Sales & T-Service	9 356.7	9 419.8	(63.1)	(135.3)	72.2
Contract Sales						
2.1	Rate 100	0.0	1.6	(1.6)	0.0 **	(1.6)
2.2	Rate 110	64.3	59.5	4.8	0.0 **	4.8
2.3	Rate 115	0.0	0.0	0.0	0.0	0.0
2.4	Rate 135	0.6	0.6	0.0	0.0	0.0
2.5	Rate 145	21.4	23.9	(2.5)	(0.2)	(2.3)
2.6	Rate 170	49.7	52.1	(2.4)	(0.2)	(2.2)
2.7	Rate 200	162.2	165.8	(3.6)	(3.7)	0.1
2.	Total Contract Sales	298.2	303.5	(5.3)	(4.1)	(1.2)
Contract T-Service						
3.1	Rate 100	0.0	6.4	(6.4)	(0.1)	(6.3)
3.2	Rate 110	423.8	429.1	(5.3)	(0.4)	(4.9)
3.3	Rate 115	532.5	548.7	(16.2)	(0.1)	(16.1)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	54.6	54.6	0.0	0.0	0.0
3.6	Rate 145	133.0	159.0	(26.0)	(0.9)	(25.1)
3.7	Rate 170	470.3	506.9	(36.6)	(1.7)	(34.9)
3.8	Rate 300	31.0	31.0	0.0	0.0	0.0
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 645.2	1 735.7	(90.5)	(3.2)	(87.3)
4.	Total Contract Sales & T-Service	1 943.4	2 039.2	(95.8)	(7.3)	(88.5)
5.	Total	11 300.1	11 459.0	(158.9)	(142.6)	(16.3)

*Note: Weather normalization adjustments have been made to the 2011 Bridge Year Estimate utilizing the 2012 Budget degree days in order to place the two years on a comparable basis.

** Less than 50,000 m³.

Witness: R. Lei

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2012 BUDGET AND 2011 BRIDGE YEAR ESTIMATE
($10^6 m^3$)

Item No.		Col. 1 2012 Budget	Col. 2 2011 Bridge Year Estimate	Col. 3 2012 Budget Over (Under) 2011 Estimate (1-2)	Col. 4 Change in Use	Col. 5 Weather	Col. 6 New Customers	Col. 7 Transfer Gains	Col. 8 Transfer Losses	Col. 9 Lost Customers	Col. 10 Added Load
General Service											
1.1.1	Rate 1 - Sales	3 693.2	3 595.4	97.8	(34.4)	(55.7)	65.5	122.4	0.0	0.0	0.0
1.1.2	Rate 1 - T-Service	890.1	1 033.7	(143.6)	(6.1)	(15.1)	0.0	0.0	(122.4)	0.0	0.0
1.1	Total Rate 1	4 583.3	4 629.1	(45.8)	(40.5)	(70.8)	65.5	122.4	(122.4)	0.0	0.0
1.2.1	Rate 6 - Sales	2 620.6	2 460.2	160.4	55.1	(32.8)	13.2	125.8	(0.9)	0.0	0.0
1.2.2	Rate 6 - T-Service	2 151.6	2 329.9	(178.3)	(47.1)	(31.7)	0.0	23.2	(122.7)	0.0	0.0
1.2	Total Rate 6	4 772.2	4 790.1	(17.9)	8.0	(64.5)	13.2	26.3	(0.9)	0.0	0.0
1.3.1	Rate 9 - Sales	1.0	0.4	0.6	0.8	0.0	0.0	0.0	0.0	(0.2)	0.0
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.3	Total Rate 9	1.2	0.6	0.6	0.8	0.0	0.0	0.0	0.0	(0.2)	0.0
1.	Total General Service	9 356.7	9 419.8	(63.1)	(31.7)	(135.3)	78.7	271.4	(246.0)	(0.2)	0.0
Contract Sales											
2.1	Rate 100	0.0	1.6	(1.6)	0.0	0.0 *	0.0	0.0	(1.6)	0.0	0.0
2.2	Rate 110	64.3	59.5	4.8	4.3	0.0 *	0.0	0.9	(0.3)	(0.1)	0.0
2.3	Rate 115	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.4	Rate 135	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.5	Rate 145	21.4	23.9	(2.5)	(1.1)	(0.2)	0.0	0.0	(1.2)	0.0	0.0
2.6	Rate 170	49.7	52.1	(2.4)	(2.2)	(0.2)	0.0	0.0	0.0	0.0	0.0
2.7	Rate 200	162.2	165.8	(3.6)	0.1	(3.7)	0.0	0.0	0.0	0.0	0.0
2.	Total Contract Sales	298.2	303.5	(5.3)	1.1	(4.1)	0.0	0.9	(3.1)	(0.1)	0.0
Contract T-Service											
3.1	Rate 100	0.0	6.4	(6.4)	0.0	(0.1)	0.0	0.0	(6.3)	0.0	0.0
3.2	Rate 110	423.8	429.1	(5.3)	(0.5)	(0.4)	0.0	0.0	(3.9)	(0.5)	0.0
3.3	Rate 115	532.5	548.7	(16.2)	(16.1)	(0.1)	0.0	0.0	0.0	0.0	0.0
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	54.6	54.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.6	Rate 145	133.0	159.0	(26.0)	(11.5)	(0.9)	0.0	0.0	(13.0)	(0.6)	0.0
3.7	Rate 170	470.3	506.9	(36.6)	(34.9)	(1.7)	0.0	0.0	0.0	0.0	0.0
3.8	Rate 300	31.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 645.2	1 735.7	(90.5)	(63.0)	(3.2)	0.0	0.0	(23.2)	(1.1)	0.0
4.	Total Contract Sales & T-Service	1 943.4	2 039.2	(95.8)	(61.9)	(7.3)	0.0	0.9	(26.3)	(1.2)	0.0
5.	Total	11 300.1	11 459.0	(158.9)	(93.6)	(142.6)	78.7	272.3	(272.3)	(1.4)	0.0

* Less than 50,000 m^3.

Witness: R. Lei

The principal reasons for the variances contributing to the weather normalized decrease of 16.3 10^6m^3 in the 2012 Budget over the 2011 Bridge Year Estimate are as follows:

1. The volumetric increase of 25.0 10^6m^3 in Rate 1 is due to customer growth of 65.5 10^6m^3; partially offset by a lower average use per customer totalling 40.5 10^6m^3;

2. The volumetric increase of 46.6 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 25.4 10^6m^3, a customer growth of 13.2 10^6m^3, and a higher average use per customer totalling 8.0 10^6m^3;

3. The volumetric increase of 0.6 10^6m^3 in Rate 9 is due to a higher average use per station of 0.8 10^6m^3; partially offset by the loss of stations of 0.2 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 88.5 10^6m^3 is due to decreases in the apartment sector of 11.4 10^6m^3, the commercial sector of 38.2 10^6m^3, the industrial sector of 39.0 10^6m^3; partially offset by the increase of Rate 200 of 0.1 10^6m^3.

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2011 BRIDGE YEAR ESTIMATE

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)
General Service			
1.1.1	Rate 1 - Sales	1 394 781	3 595.4
1.1.2	Rate 1 - T-Service	405 147	1 033.7
1.1	Total Rate 1	1 799 928	4 629.1
1.2.1	Rate 6 - Sales	123 260	2 460.2
1.2.2	Rate 6 - T-Service	34 080	2 329.9
1.2	Total Rate 6	157 340	4 790.1
1.3.1	Rate 9 - Sales	10	0.4
1.3.2	Rate 9 - T-Service	1	0.2
1.3	Total Rate 9	11	0.6
1.	Total General Service Sales & T-Service	1 957 279	9 419.8
Contract Sales			
2.1	Rate 100	3	1.6
2.2	Rate 110	35	59.5
2.3	Rate 115	0	0.0
2.4	Rate 135	1	0.6
2.5	Rate 145	11	23.9
2.6	Rate 170	5	52.1
2.7	Rate 200	1	165.8
2.	Total Contract Sales	56	303.5
Contract T-Service			
3.1	Rate 100	7	6.4
3.2	Rate 110	170	429.1
3.3	Rate 115	30	548.7
3.4	Rate 125	4	0.0 *
3.5	Rate 135	37	54.6
3.6	Rate 145	109	159.0
3.7	Rate 170	33	506.9
3.8	Rate 300	8	31.0
3.9	Rate 315	0	0.0
3.	Total Contract T-Service	398	1 735.7
4.	Total Contract Sales & T-Service	454	2 039.2
5.	Total	1 957 733	11 459.0

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 BRIDGE YEAR ESTIMATE AND 2011 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2011 Bridge Year Estimate	Col. 2 2011 Budget	Col. 3 2011 Estimate Over (Under) 2011 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 595.4	3 356.3	239.1
1.1.2	Rate 1 - T-Service	1 033.7	1 408.1	(374.4)
1.1	Total Rate 1	4 629.1	4 764.4	(135.3)
1.2.1	Rate 6 - Sales	2 460.2	2 235.7	224.5
1.2.2	Rate 6 - T-Service	2 329.9	2 282.7	47.2
1.2	Total Rate 6	4 790.1	4 518.4	271.7
1.3.1	Rate 9 - Sales	0.4	0.4	0.0
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0
1.3	Total Rate 9	0.6	0.6	0.0
1.	Total General Service Sales & T-Service	9 419.8	9 283.4	136.4
Contract Sales				
2.1	Rate 100	1.6	0.0	1.6
2.2	Rate 110	59.5	64.5	(5.0)
2.3	Rate 115	0.0	0.4	(0.4)
2.4	Rate 135	0.6	0.6	0.0
2.5	Rate 145	23.9	22.3	1.6
2.6	Rate 170	52.1	49.9	2.2
2.7	Rate 200	165.8	157.4	8.4
2.	Total Contract Sales	303.5	295.1	8.4
Contract T-Service				
3.1	Rate 100	6.4	0.0	6.4
3.2	Rate 110	429.1	407.4	21.7
3.3	Rate 115	548.7	512.7	36.0
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	54.6	49.4	5.2
3.6	Rate 145	159.0	215.0	(56.0)
3.7	Rate 170	506.9	513.3	(6.4)
3.8	Rate 300	31.0	30.0	1.0
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 735.7	1 727.8	7.9
4.	Total Contract Sales & T-Service	2 039.2	2 022.9	16.3
5.	Total	11 459.0	11 306.3	152.7

* There is no distribution volume for Rate 125 customers.

Witness: R. Lei

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 BRIDGE YEAR ESTIMATE AND 2011 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2011 Bridge Year Estimate	Col. 2 2011 Budget	Col. 3 2011 Estimate Over (Under) 2011 Budget (1-2)	Col. 4 2011* Adjustments	Col. 5 2011 Estimate Over (Under) 2011 Budget with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 595.4	3 356.3	239.1	0.0	239.1
1.1.2	Rate 1 - T-Service	1 033.7	1 408.1	(374.4)	0.0	(374.4)
1.1	Total Rate 1	4 629.1	4 764.4	(135.3)	0.0	(135.3)
1.2.1	Rate 6 - Sales	2 460.2	2 235.7	224.5	0.0	224.5
1.2.2	Rate 6 - T-Service	2 329.9	2 282.7	47.2	0.0	47.2
1.2	Total Rate 6	4 790.1	4 518.4	271.7	0.0	271.7
1.3.1	Rate 9 - Sales	0.4	0.4	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0	0.0	0.0
1.3	Total Rate 9	0.6	0.6	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	9 419.8	9 283.4	136.4	0.0	136.4
Contract Sales						
2.1	Rate 100	1.6	0.0	1.6	0.0	1.6
2.2	Rate 110	59.5	64.5	(5.0)	0.0	(5.0)
2.3	Rate 115	0.0	0.4	(0.4)	0.0	(0.4)
2.4	Rate 135	0.6	0.6	0.0	0.0	0.0
2.5	Rate 145	23.9	22.3	1.6	0.0	1.6
2.6	Rate 170	52.1	49.9	2.2	0.0	2.2
2.7	Rate 200	165.8	157.4	8.4	0.0	8.4
2.	Total Contract Sales	303.5	295.1	8.4	0.0	8.4
Contract T-Service						
3.1	Rate 100	6.4	0.0	6.4	0.0	6.4
3.2	Rate 110	429.1	407.4	21.7	0.0	21.7
3.3	Rate 115	548.7	512.7	36.0	0.0	36.0
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	54.6	49.4	5.2	0.0	5.2
3.6	Rate 145	159.0	215.0	(56.0)	0.0	(56.0)
3.7	Rate 170	506.9	513.3	(6.4)	0.0	(6.4)
3.8	Rate 300	31.0	30.0	1.0	0.0	1.0
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 735.7	1 727.8	7.9	0.0	7.9
4.	Total Contract Sales & T-Service	2 039.2	2 022.9	16.3	0.0	16.3
5.	Total	11 459.0	11 306.3	152.7	0.0	152.7

*Note: As 2011 Bridge Year Estimate degree days are same as 2011 Board Approved Budget Degree Days, normalization adjustment is not required in order to place the two years on a comparable basis.

The principal reasons for the variances contributing to the weather normalized increase of 152.7 10^6m^3 in the 2011 Bridge Year Estimate over the 2011 Board Approved Budget are as follows:

1. The volumetric decrease of 135.3 10^6m^3 in Rate 1 is due to a lower average use per customer totalling 126.6 10^6m^3 and a unfavourable customer variance of 8.7 10^6m^3;

2. The volumetric increase of 271.7 10^6m^3 in Rate 6 is due to a higher average use per customer totalling 303.0 10^6m^3 and net customer migration from Contract Sales and T-Service of 33.0 10^6m^3; partially offset by an unfavourable customer variance of 64.3 10^6m^3;

3. The volumetric increase for Contract Sales and T-Service of 16.3 10^6m^3 is due to increases in the commercial sector of 12.8 10^6m^3, in the industrial sector of 21.7 10^6m^3 and Rate 200 of 8.4 10^6m^3; partially offset by decrease in the apartment sector of 26.6 10^6m^3.

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2011 BRIDGE YEAR ESTIMATE AND 2010 ACTUAL

Item No.		Col. 1 2011 Bridge Year Estimate	Col. 2 2010 Actual	Col. 3 2011 Estimate Over (Under) 2010 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 394 781	1 260 809	133 972
1.1.2	Rate 1 - T-Service	405 147	511 694	(106 547)
1.1	Total Rate 1	1 799 928	1 772 503	27 425
1.2.1	Rate 6 - Sales	123 260	112 380	10 880
1.2.2	Rate 6 - T-Service	34 080	40 829	(6 749)
1.2	Total Rate 6	157 340	153 209	4 131
1.3.1	Rate 9 - Sales	10	22	(12)
1.3.2	Rate 9 - T-Service	1	1	0
1.3	Total Rate 9	11	23	(12)
1.	Total General Service Sales & T-Service	1 957 279	1 925 735	31 544
Contract Sales				
2.1	Rate 100	3	7	(4)
2.2	Rate 110	35	37	(2)
2.3	Rate 115	0	0	0
2.4	Rate 135	1	6	(5)
2.5	Rate 145	11	14	(3)
2.6	Rate 170	5	6	(1)
2.7	Rate 200	1	1	0
2.	Total Contract Sales	56	71	(15)
Contract T-Service				
3.1	Rate 100	7	28	(21)
3.2	Rate 110	170	176	(6)
3.3	Rate 115	30	32	(2)
3.4	Rate 125	4	4	0
3.5	Rate 135	37	30	7
3.6	Rate 145	109	174	(65)
3.7	Rate 170	33	35	(2)
3.8	Rate 300	8	9	(1)
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	398	488	(90)
4.	Total Contract Sales & T-Service	454	559	(105)
5.	Total	1 957 733	1 926 294	31 439

Witness: R. Lei

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 BRIDGE YEAR ESTIMATE AND 2010 ACTUAL
($10^6 m^3$)

Item No.		Col. 1 2011 Bridge Year Estimate	Col. 2 2010 Actual	Col. 3 2011 Estimate Over (Under) 2010 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 595.4	3 119.2	476.2
1.1.2	Rate 1 - T-Service	1 033.7	1 294.7	(261.0)
1.1	Total Rate 1	4 629.1	4 413.9	215.2
1.2.1	Rate 6 - Sales	2 460.2	1 959.3	500.9
1.2.2	Rate 6 - T-Service	2 329.9	2 382.7	(52.8)
1.2	Total Rate 6	4 790.1	4 342.0	448.1
1.3.1	Rate 9 - Sales	0.4	1.0	(0.6)
1.3.2	Rate 9 - T-Service	0.2	0.1	0.1
1.3	Total Rate 9	0.6	1.1	(0.5)
1.	Total General Service Sales & T-Service	9 419.8	8 757.0	662.8
Contract Sales				
2.1	Rate 100	1.6	4.8	(3.2)
2.2	Rate 110	59.5	69.1	(9.6)
2.3	Rate 115	0.0	(2.1)	2.1
2.4	Rate 135	0.6	5.6	(5.0)
2.5	Rate 145	23.9	22.0	1.9
2.6	Rate 170	52.1	37.8	14.3
2.7	Rate 200	165.8	169.6	(3.8)
2.	Total Contract Sales	303.5	306.8	(3.3)
Contract T-Service				
3.1	Rate 100	6.4	17.8	(11.4)
3.2	Rate 110	429.1	493.3	(64.2)
3.3	Rate 115	548.7	480.1	68.6
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	54.6	67.4	(12.8)
3.6	Rate 145	159.0	211.2	(52.2)
3.7	Rate 170	506.9	579.4	(72.5)
3.8	Rate 300	31.0	27.6	3.4
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 735.7	1 876.8	(141.1)
4.	Total Contract Sales & T-Service	2 039.2	2 183.6	(144.4)
5.	Total	11 459.0	10 940.6	518.4

* There is no distribution volume for Rate 125 customers.

Witness: R. Lei

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 BRIDGE YEAR ESTIMATE AND 2010 ACTUAL
($10^6 m^3$)

Item No.		Col. 1 2011 Bridge Year Estimate	Col. 2 2010 Actual	Col. 3 2011 Estimate Over (Under) 2010 Actual (1-2)	Col. 4 2010* Adjustments	Col. 5 2011 Estimate Over (Under) 2010 Actual with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 595.4	3 119.2	476.2	134.3	341.9
1.1.2	Rate 1 - T-Service	1 033.7	1 294.7	(261.0)	109.2	(370.2)
1.1	Total Rate 1	4 629.1	4 413.9	215.2	243.5	(28.3)
1.2.1	Rate 6 - Sales	2 460.2	1 959.3	500.9	78.9	422.0
1.2.2	Rate 6 - T-Service	2 329.9	2 382.7	(52.8)	110.5	(163.3)
1.2	Total Rate 6	4 790.1	4 342.0	448.1	189.4	258.7
1.3.1	Rate 9 - Sales	0.4	1.0	(0.6)	0.0	(0.6)
1.3.2	Rate 9 - T-Service	0.2	0.1	0.1	0.0	0.1
1.3	Total Rate 9	0.6	1.1	(0.5)	0.0	(0.5)
1.	Total General Service Sales & T-Service	9 419.8	8 757.0	662.8	432.9	229.9
Contract Sales						
2.1	Rate 100	1.6	4.8	(3.2)	0.1	(3.3)
2.2	Rate 110	59.5	69.1	(9.6)	0.1	(9.7)
2.3	Rate 115	0.0	(2.1)	2.1	0.0	2.1
2.4	Rate 135	0.6	5.6	(5.0)	0.0	(5.0)
2.5	Rate 145	23.9	22.0	1.9	0.7	1.2
2.6	Rate 170	52.1	37.8	14.3	0.3	14.0
2.7	Rate 200	165.8	169.6	(3.8)	3.7	(7.5)
2.	Total Contract Sales	303.5	306.8	(3.3)	4.9	(8.2)
Contract T-Service						
3.1	Rate 100	6.4	17.8	(11.4)	0.2	(11.6)
3.2	Rate 110	429.1	493.3	(64.2)	0.2	(64.4)
3.3	Rate 115	548.7	480.1	68.6	0.1	68.5
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	54.6	67.4	(12.8)	0.0	(12.8)
3.6	Rate 145	159.0	211.2	(52.2)	1.0	(53.2)
3.7	Rate 170	506.9	579.4	(72.5)	0.6	(73.1)
3.8	Rate 300	31.0	27.6	3.4	0.0	3.4
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 735.7	1 876.8	(141.1)	2.1	(143.2)
4.	Total Contract Sales & T-Service	2 039.2	2 183.6	(144.4)	7.0	(151.4)
5.	Total	11 459.0	10 940.6	518.4	439.9	78.5

* Note: Weather normalization adjustments have been made to the 2010 Actuals utilizing the 2011 Board Approved Budget degree days in order to place the two years on a comparable basis.

** Less than 50,000 m^3.

Witness: R. Lei

The principal reasons for the variances contributing to the weather normalized increase of 78.5 10^6m^3 in the 2011 Bridge Year Estimate over the 2010 Actual are as follows:

1. The volumetric decrease of 28.3 10^6m^3 in Rate 1 is due to a lower average use per customer totalling 97.3 10^6m^3; partially offset by customer growth of 69.0 10^6m^3;

2. The volumetric increase of 258.7 10^6m^3 in Rate 6 is due to net customer growth of 114.3 10^6m^3, higher average use per customer totalling 82.2 10^6m^3 and net customer migration from Contract Sales and T-Service of 62.2 10^6m^3.

3. The volumetric decrease of 0.5 10^6m^3 in Rate 9 is due to the loss of stations of 0.6 10^6m^3; partially offset by a higer average use per station of 0.1 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 151.4 10^6m^3 is due to decreases in the apartment sector of 45.7 10^6m^3, the industrial sector of 202.4 10^6m^3 and Rate 200 of 7.5 10^6m^3; partially offset by an increase in commercial sector of 104.2 10^6m^3. This decrease is primarily attributable to net customer migration to General Service of 62.2 10^6m^3 as stated above.

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED 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
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011 Bridge Year Estimate	2012 Budget
Rate 1		2,991	2,880	2,859	2,843	2,799	2,731	2,700	2,695	2,665	2,614	2,577	2,533	2,510
	Change		(111)	(21)	(16)	(44)	(68)	(31)	(5)	(30)	(51)	(37)	(44)	(23)
	% Change		-3.71%	-0.73%	-0.56%	-1.55%	-2.43%	-1.14%	-0.19%	-1.11%	-1.91%	-1.42%	-1.71%	-0.91%
Rate 6		21,685	21,325	21,213	21,387	21,078	20,573	21,173	22,474	25,129	26,889	29,148	29,878	30,122
	Change		(360)	(112)	174	(309)	(505)	600	1,301	2,655	1,760	2,259	730	244
	% Change		-1.66%	-0.53%	0.82%	-1.44%	-2.40%	2.92%	6.14%	11.81%	7.00%	8.40%	2.50%	0.82%

* All historical average uses are on a calendar-year basis and have been normalized to the 2012 Budget degree days.

Witness: R. Lei

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED 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
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011 Bridge Year Estimate	2012 Budget
Residential		2,991	2,880	2,859	2,843	2,799	2,731	2,700	2,695	2,665	2,614	2,577	2,533	2,510
	Change		(111)	(21)	(16)	(44)	(68)	(31)	(5)	(30)	(51)	(37)	(44)	(23)
	% Change		-3.71%	-0.73%	-0.56%	-1.55%	-2.43%	-1.14%	-0.19%	-1.11%	-1.91%	-1.42%	-1.71%	-0.91%
Apartment		79,653	79,937	80,932	82,214	82,219	78,769	86,334	100,411	125,142	142,812	162,972	159,575	160,301
	Change		284	995	1,282	5	(3,450)	7,565	14,077	24,731	17,670	20,160	(3,397)	726
	% Change		0.36%	1.24%	1.58%	0.01%	-4.20%	9.60%	16.31%	24.63%	14.12%	14.12%	-2.08%	0.45%
Commercial		17,346	17,133	17,096	17,096	16,965	16,574	16,775	17,242	18,119	18,689	19,409	19,853	19,921
	Change		(213)	(37)	0	(131)	(391)	201	467	877	570	720	444	68
	% Change		-1.23%	-0.22%	0.00%	-0.77%	-2.30%	1.21%	2.78%	5.09%	3.15%	3.85%	2.29%	0.34%
Industrial		57,367	54,464	52,132	55,052	50,787	51,721	54,437	59,392	74,494	88,420	107,096	111,040	114,225
	Change		(2,903)	(2,332)	2,920	(4,265)	934	2,716	4,955	15,102	13,926	18,676	3,944	3,185
	% Change		-5.06%	-4.28%	5.60%	-7.75%	1.84%	5.25%	9.10%	25.43%	18.69%	21.12%	3.68%	2.87%

* All historical average uses are on a calendar-year basis and have been normalized to the 2012 Budget degree days.

GENERAL SERVICE AVERAGE USES
HISTORICAL NORMALIZED ACTUAL AND BOARD APPROVED - FISCAL AND CALENDAR YEARS

In order to compare the year over year variance between actual and Board Approved normalized average uses on the same basis, each year actual results have to be normalized to the corresponding Board Approved degree days for that year. As both of historical Board Approved degree days and average uses were developed based upon fiscal year information up to 2005, they are presented on a fiscal-year basis up to 2005 in this exhibit. From 2006 onwards, they are presented on a calendar-year basis.

The actual average uses on the next page have been normalized to the corresponding Board Approved degree days for that year.

The average uses on the next page are different from those presented on page 21. The average uses reported on page 21 are all normalized to the test year degree days instead of each year's corresponding Board Approved degree days and they are all presented on a calendar-year basis.

GENERAL SERVICE AVERAGE USES

	Test Year	Rate Classes	Col. 1 Actual Normalized Average Use (m^3)	Col. 2 Board Approved Normalized Average Use (m^3)	Col. 3 Variance Normalized Average Use (1-2)	Col. 4 %Variance Normalized Average Use (3/2)*100
FISCAL YEAR	2001	Rate 1	3,014	3,044	(30)	-1.0%
		Rate 6	22,510	22,643	(133)	-0.6%
		Total General Service	4,817	4,861	(44)	-0.9%
	2002	Rate 1	2,980	2,970	10	0.3%
		Rate 6	22,097	22,125	(28)	-0.1%
		Total General Service	4,710	4,756	(46)	-1.0%
	2003	Rate 1	2,877	2,892	(15)	-0.5%
		Rate 6	21,593	21,685	(92)	-0.4%
		Total General Service	4,541	4,579	(38)	-0.8%
	2004*	Rate 1	2,843	2,857	(14)	-0.5%
		Rate 6	21,472	21,612	(140)	-0.6%
		Total General Service	4,461	4,502	(41)	-0.9%
	2005	Rate 1	2,890	2,953	(63)	-2.1%
		Rate 6	22,241	22,507	(266)	-1.2%
		Total General Service	4,547	4,646	(99)	-2.1%
CALENDAR YEAR	2006	Rate 1	2,796	2,850	(54)	-1.9%
		Rate 6	22,272	21,999	273	1.2%
		Total General Service	4,444	4,438	6	0.1%
	2007	Rate 1	2,726	2,687	39	1.5%
		Rate 6	22,783	21,010	1,773	8.4%
		Total General Service	4,412	4,200	212	5.0%
	2008	Rate 1	2,636	2,647	(11)	-0.4%
		Rate 6	24,869	24,204	665	2.7%
		Total General Service	4,493	4,449	44	1.0%
	2009	Rate 1	2,604	2,637	(33)	-1.3%
		Rate 6	27,281	28,165	(884)	-3.1%
		Total General Service	4,659	4,770	(111)	-2.3%
	2010	Rate 1	2,579	2,622	(43)	-1.6%
		Rate 6	29,106	27,949	1,157	4.1%
		Total General Service	4,403	4,705	(302)	-6.4%
	2011**	Rate 1	2,573	2,643	(70)	-2.7%
		Rate 6	30,327	28,029	2,298	8.2%
		Total General Service	4,812	4,726	86	1.8%
	2012	Rate 1		2,510		
		Rate 6		30,122		
		Total General Service		4,715		

* 2004 Bridge Year Estimate from RP-2003-0203 was reported at column 2 because Board Approved numbers are not available since there was no 2004 Board Approved Volumes Budget due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

**2011 Bridge Year Estimate was reported at column 1 because actual numbers are not available

LARGE VOLUME (CONTRACT) CUSTOMER DEMAND

HISTORICAL NORMALIZED ACTUAL AND BOARD APPROVED - FISCAL AND CALENDAR YEARS

In order to compare the year over year variance between actual and Board Approved normalized contract demand on the same basis, each year actual results have to be normalized to the corresponding Board Approved degree days for that year. As both of historical Board Approved degree days and volumes were developed based upon fiscal year information up to 2005, they are presented on a fiscal-year basis up to 2005 in this exhibit. From 2006 onwards, they are presented on a calendar-year basis.

The actual consumption on the next page have been normalized to the corresponding Board Approved degree days for that year. Contract market customers' volumes are much less weather sensitive than General Service customers'.

CONTRACT CUSTOMERS NORMALIZED VOLUME

	Test Year	Col. 1 Actual Normalized Consumption (10^6m^3)	Col. 2 Board Approved Normalized Consumption (10^6m^3)	Col. 3 Variance Normalized Consumption (1-2)	Col. 4 %Variance Normalized Consumption (3/2)*100
FISCAL YEAR	2001	4,292.5	4,517.1	(224.6)	-5.0%
	2002	4,433.6	4,355.6	78.0	1.8%
	2003	4,380.7	4,400.2	(19.5)	-0.4%
	2004*	4,275.7	4,309.7	(34.0)	-0.8%
	2005	4,199.2	4,334.2	(135.0)	-3.1%
CALENDAR YEAR	2006	4,119.1	4,387.9	(268.8)	-6.1%
	2007	3,739.8	4,134.3	(394.5)	-9.5%
	2008	3,099.6	3,355.2	(255.6)	-7.6%
	2009	2,191.4	2,316.6	(125.2)	-5.4%
	2010	2,175.7	2,008.6	167.1	8.3%
	2011**	2,039.2	2,022.9	16.3	0.8%
	2012		1,943.4		

* 2004 Bridge Year Estimate from RP-2003-0203 was reported at column 2 because Board Approved numbers are not available since there was no 2004 Board Approved Volumes Budget due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

**2011 Bridge Year Estimate was reported at column 1 because actual numbers are not available.

BUDGET DEGREE DAYS

1. The purpose of this evidence is to provide the degree day forecasts for 2012[1].

2. The 2012 degree day forecasts were prepared in accordance with the Board's EB-2006-0034 Decision with Reasons – Phase 1 dated July 5, 2007. The Company has produced a forecast of Environment Canada degree days for each of the three weather zones within its franchise area using the 20-Year Trend method for the Central weather zone, the Energy Probe method for the Eastern weather zone and the 50/50 method for the Niagara weather zone. For 2012, the degree day forecasts are as follows:
   a. Central weather zone: 3,557 Environment Canada degree days; 3,532 Gas Supply degree days
   b. Eastern weather zone: 4,382 Environment Canada degree days; 4,343 Gas Supply degree days
   c. Niagara weather zone: 3,468 Environment Canada degree days; 3,418 Gas Supply degree days

Degree Day Forecast Methodology

3. The degree day forecast for the Central weather zone was prepared using the 20-Year Trend method. This method regresses actual Environment Canada degree days on a constant and trend. Table 1 displays the actual Environment Canada degree day data for the Central weather zone and trend data used to estimate the model and the resultant degree day forecast for 2012. The model is estimated using data covering the period 1991 to 2010, a period of 20 years. Estimation results are provided in Figure 1.

[1] All degree day data, models and forecasts are calculated using a calendar (i.e. December) year end.

4. The degree day forecast for the Eastern weather zone was prepared using the Energy Probe method. This method regresses actual Environment Canada degree days on a constant, a 5 year weighted average of Environment Canada degree days, a 5 year moving average of Environment Canada degree days and a trend[2]. The 5 year weighted averages and 5 year moving averages are lagged 2 years. Table 2 displays the actual Environment Canada degree day data for the Eastern weather zone, the 5 year weighted and moving averages and the trend data used to estimate the model. The resultant degree day forecast for 2012 is presented in Table 2 as well. The model is estimated over the period 1950 to 2010 a total of 61 years as indicated by the cycle length. Estimation results are provided in Figure 2.

5. The degree day forecast for the Niagara weather zone was prepared using the 50/50 method. This method is an average of the degree day forecasts generated from the 20-Year Trend method and a 30-year moving average. Table 3 displays the actual Environment Canada degree day data for the Niagara weather zone and the trend data used to estimate the 20-Year Trend model, the 30-year moving averages and the resultant degree day forecasts from both methods[3]. The final degree day forecast is a simple average of the degree day forecasts produced by each method. The 20-Year Trend model is estimated over the period 1991 to 2010 for a period of 20 years while the 30-year moving average is calculated using an average of actual degree days over the period from 1981 to 2010, a period of 30 years. Estimation results for the 20-Year Trend model are provided in Figure 3.

[2] The five-year weighted average for year *t* is calculated as $(5*DD_{t-2}+4*DD_{t-3}+3*DD_{t-4}+2*DD_{t-5}+DD_{t-6})/15$ while the five-year moving average at year *t* is computed as $(DD_{t-2} + DD_{t-3} + DD_{t-4} + DD_{t-5} + DD_{t-6})/5$ where DD is the actual degree day value.

[3] The 30 year moving average for year *t* is calculated as $(DD_{t-2}+DD_{t-3}+ \dots +DD_{t-30}+DD_{t-31})/30$ where DD is the actual degree day value.

Table 1
Environment Canada Degree Day Forecast – Central

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	Actual[1]	Trend	Fitted[2]
1991	3,686	1	3,985
1992	4,112	2	3,964
1993	4,180	3	3,944
1994	4,115	4	3,923
1995	4,040	5	3,903
1996	4,177	6	3,883
1997	4,026	7	3,862
1998	3,220	8	3,842
1999	3,539	9	3,822
2000	3,826	10	3,801
2001	3,420	11	3,781
2002	3,630	12	3,760
2003	3,982	13	3,740
2004	3,798	14	3,720
2005	3,797	15	3,699
2006	3,378	16	3,679
2007	3,722	17	3,659
2008	3,837	18	3,638
2009	3,836	19	3,618
2010	3,501	20	3,598
2012 Forecast		22	3,557

[1]Environment Canada heating degree day observations from Pearson International Airport.
[2]Calculated using the 20-year Trend regression equation from Figure 1.

Table 2
Environment Canada Degree Day Forecast – Eastern

Col. 1	*Col. 2*	*Col. 3*	*Col.4*	*Col.5*	*Col. 6*
Calendar Year	Actual[1]	Trend	5-year MA[2]	5-year Weighted MA[3]	Fitted[4]
1950	4,824	1	4,677	4,665	4,735
1951	4,587	2	4,622	4,594	4,711
1952	4,404	3	4,647	4,661	4,733
1953	4,059	4	4,657	4,641	4,715
1954	4,707	5	4,572	4,556	4,694
1955	4,689	6	4,467	4,385	4,635
1956	4,799	7	4,516	4,465	4,656
1957	4,405	8	4,489	4,523	4,688
1958	4,736	9	4,531	4,626	4,723
1959	4,718	10	4,532	4,584	4,697
1960	4,451	11	4,667	4,652	4,686
1961	4,586	12	4,669	4,669	4,689
1962	4,826	13	4,622	4,596	4,662
1963	4,921	14	4,579	4,584	4,665
1964	4,569	15	4,663	4,667	4,676
1965	4,810	16	4,701	4,753	4,704
1966	4,683	17	4,671	4,709	4,686
1967	4,882	18	4,743	4,755	4,683
1968	4,780	19	4,762	4,735	4,663
1969	4,698	20	4,773	4,775	4,675
1970	4,899	21	4,745	4,778	4,680
1971	4,797	22	4,771	4,762	4,660
1972	5,014	23	4,788	4,805	4,671
1973	4,420	24	4,811	4,808	4,661
1974	4,725	25	4,838	4,876	4,683
1975	4,514	26	4,766	4,736	4,630
1976	5,008	27	4,771	4,723	4,617
1977	4,597	28	4,694	4,637	4,593
1978	4,939	29	4,736	4,741	4,628
1979	4,589	30	4,652	4,695	4,625
1980	4,920	31	4,756	4,790	4,637
1981	4,438	32	4,729	4,735	4,613
1982	4,647	33	4,810	4,798	4,616
1983	4,536	34	4,697	4,674	4,584
1984	4,535	35	4,707	4,658	4,568
1985	4,659	36	4,626	4,601	4,559
1986	4,501	37	4,615	4,570	4,542
1987	4,328	38	4,563	4,585	4,561
1988	4,640	39	4,576	4,564	4,542
1989	4,931	40	4,512	4,482	4,516
1990	4,250	41	4,532	4,524	4,526
1991	4,303	42	4,612	4,657	4,564
1992	4,861	43	4,530	4,537	4,524
1993	4,780	44	4,490	4,461	4,493
1994	4,730	45	4,597	4,585	4,519
1995	4,585	46	4,625	4,646	4,536
1996	4,603	47	4,585	4,681	4,561
1997	4,786	48	4,652	4,680	4,537
1998	3,828	49	4,712	4,664	4,506
1999	4,137	50	4,697	4,689	4,518
2000	4,543	51	4,506	4,399	4,426
2001	4,115	52	4,387	4,276	4,395
2002	4,381	53	4,379	4,328	4,419
2003	4,715	54	4,282	4,240	4,400
2004	4,637	55	4,201	4,273	4,436
2005	4,421	56	4,378	4,444	4,464
2006	4,037	57	4,478	4,531	4,473
2007	4,447	58	4,454	4,511	4,466
2008	4,488	59	4,438	4,373	4,397
2009	4,534	60	4,451	4,376	4,390
2010	3,973	61	4,406	4,388	4,405
2012 Forecast		63	4,296	4,293	4,382

[1]Environment Canada heating degree day observations from MacDonald-Cartier Airport.
[2]5-year moving average lagged 2 years.
[3]5-year weighted average lagged 2 years.
[4]Calculated using the Energy Probe regression equation from Figure 2.

Table 3
Environment Canada Degree Day Forecast – Niagara

Col. 1	*Col. 2*	*Col. 3*	*Col.4*	*Col.5*	*Col. 6*
Calendar Year	Actual[1]	Trend	30-Year Moving Average[2]	20-Year Trend[3]	Fitted[4]
1981	3,729		3,664		
1982	3,724		3,678		
1983	3,642		3,682		
1984	3,716		3,691		
1985	3,651		3,697		
1986	3,603		3,707		
1987	3,441		3,712		
1988	3,693		3,705		
1989	3,845		3,697		
1990	3,307		3,705		
1991	3,343	1	3,711	3,656	3,684
1992	3,759	2	3,697	3,642	3,670
1993	3,878	3	3,687	3,628	3,657
1994	3,780	4	3,692	3,613	3,652
1995	3,703	5	3,693	3,599	3,646
1996	3,786	6	3,701	3,585	3,643
1997	3,669	7	3,693	3,571	3,632
1998	2,980	8	3,704	3,556	3,630
1999	3,338	9	3,699	3,542	3,621
2000	3,596	10	3,670	3,528	3,599
2001	3,239	11	3,665	3,514	3,589
2002	3,415	12	3,659	3,499	3,579
2003	3,799	13	3,645	3,485	3,565
2004	3,632	14	3,631	3,471	3,551
2005	3,653	15	3,642	3,456	3,549
2006	3,163	16	3,639	3,442	3,541
2007	3,296	17	3,644	3,428	3,536
2008	3,480	18	3,619	3,414	3,516
2009	3,565	19	3,604	3,399	3,502
2010	3,344	20	3,586	3,385	3,486
2012 Forecast		22	3,578	3,357	3,468

[1]Environment Canada heating degree day observations from St. Catherines Airport until August 2008. Effective September 2008 Environment Canada is no longer able to provide degree day data for St.Catherines Airport. Data from September 2008 and thereafter are now obtained from the Vineland Climate Station.
[2]30 year moving average.
[3]Calculated using the 20-year Trend regression equation from Figure 3.
[4]Based on the 50/50 Method which is an average of columns 4 and 5.

Figure 1
20-Year Trend Forecasting Equation and Test Statistics - Central

Sample: 1991 2010 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	5,023.3180	612.23	8.20	0.00
TREND	-20.3687	10.07	-2.02	0.06

R-squared	0.19	F-statistic	4.09
Adjusted R-squared	0.14	F-prob	0.06

Figure 2
Energy Probe Forecasting Equation and Test Statistics - Eastern

Sample: 1950 2010 Included observations: 61

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	3,850.8220	1,252.25	3.08	0.00
ECEDD5WA	0.5015	0.72	0.70	0.49
ECEDD5MA	-4.5438	2.04	-2.23	0.03
TREND	-0.3015	0.77	-0.39	0.70

R-squared	0.15	F-statistic	3.37
Adjusted R-squared	0.11	F-prob	0.02

Figure 3
20-Year Trend Forecasting Equation and Test Statistics - Niagara

Sample: 1991 2010 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	4,383.9030	559.99	7.83	0.00
TREND	-14.2679	9.21	-1.55	0.14

R-squared	0.12	F-statistic	2.40
Adjusted R-squared	0.07	F-prob	0.14

Witness: H.Sayyan

6. The final step in the degree day forecast involves the conversion of Environment Canada degree days to Gas Supply degree days. This conversion is done by regressing actual Gas Supply degree days onto actual Environment Canada degree days. The resultant equation (one for each weather zone) is used to convert the Environment Canada degree day forecast to the Gas Supply degree day forecast. Tables 4, 5 and 6 display actual Environment Canada degree days, actual Gas Supply degree days, and the resultant Gas Supply degree day forecasts for the 2012 test year.

Table 4

Determination of Gas Supply Equivalent Degree Days - Central

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	**Actual Environment Canada Degree Days**	**Actual Gas Supply Degree Days**	**Fitted Gas Supply Degree Days**[1]
1991	3,686	3,649	3,650
1992	4,112	3,989	4,041
1993	4,180	4,040	4,104
1994	4,115	4,084	4,044
1995	4,040	3,991	3,975
1996	4,177	4,133	4,100
1997	4,026	3,966	3,962
1998	3,220	3,202	3,223
1999	3,539	3,497	3,516
2000	3,826	3,784	3,779
2001	3,420	3,400	3,407
2002	3,630	3,597	3,599
2003	3,982	3,949	3,921
2004	3,798	3,766	3,753
2005	3,797	3,750	3,752
2006	3,378	3,355	3,368
2007	3,722	3,659	3,683
2008	3,837	3,801	3,788
2009	3,836	3,767	3,788
2010	3,501	3,466	3,481
2012 Forecast	3,557		3,532

[1]Fitted and forecast Gas Supply degree days are calculated using the following regression equation:

Gas Supply degree days = 271.2545+0.9167(Environment Canada degree days)

Witness: H.Sayyan

Table 5
Determination of Gas Supply Equivalent Degree Days - Eastern

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	**Actual Environment Canada Degree Days**	**Actual Gas Supply Degree Days**	**Fitted Gas Supply Degree Days[1]**
1970	4,899	5,018	4,839
1971	4,797	4,584	4,742
1972	5,014	4,816	4,950
1973	4,420	4,480	4,379
1974	4,725	4,858	4,672
1975	4,514	4,229	4,470
1976	5,008	4,901	4,944
1977	4,597	4,604	4,549
1978	4,939	4,920	4,878
1979	4,589	4,550	4,542
1980	4,920	4,853	4,860
1981	4,438	4,361	4,397
1982	4,647	4,617	4,598
1983	4,536	4,515	4,491
1984	4,535	4,504	4,490
1985	4,659	4,648	4,609
1986	4,501	4,507	4,458
1987	4,328	4,268	4,291
1988	4,640	4,601	4,590
1989	4,931	4,883	4,870
1990	4,250	4,225	4,217
1991	4,303	4,270	4,268
1992	4,861	4,746	4,803
1993	4,780	4,715	4,726
1994	4,730	4,700	4,677
1995	4,585	4,530	4,538
1996	4,603	4,561	4,555
1997	4,786	4,711	4,731
1998	3,828	3,802	3,812
1999	4,137	4,112	4,108
2000	4,543	4,506	4,498
2001	4,115	4,071	4,087
2002	4,381	4,317	4,342
2003	4,715	4,663	4,663
2004	4,637	4,598	4,588
2005	4,421	4,397	4,380
2006	4,037	4,012	4,013
2007	4,447	4,411	4,406
2008	4,488	4,431	4,445
2009	4,534	4,472	4,489
2010	3,973	3,947	3,951
2012 Forecast	4,382		4,343

[1]Fitted and forecast Gas Supply degree days are calculated using the following regression equation:

Gas Supply degree days = 140.4521+0.9591(Environment Canada degree days)

Witness: H.Sayyan

Table 6

Determination of Gas Supply Equivalent Degree Days - Niagara

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	**Actual Environment Canada Degree Days**	**Actual Gas Supply Degree Days**	**Fitted Gas Supply Degree Days**[1]
1986	3,603	3,384	3,526
1987	3,441	3,600	3,397
1988	3,693	3,611	3,597
1989	3,845	3,599	3,717
1990	3,307	3,511	3,290
1991	3,343	3,287	3,319
1992	3,759	3,636	3,649
1993	3,878	3,667	3,744
1994	3,780	3,616	3,666
1995	3,703	3,577	3,605
1996	3,786	3,808	3,671
1997	3,669	3,646	3,577
1998	2,980	2,931	3,031
1999	3,338	3,277	3,315
2000	3,596	3,553	3,520
2001	3,239	3,162	3,237
2002	3,415	3,304	3,376
2003	3,799	3,688	3,681
2004	3,632	3,485	3,548
2005	3,653	3,580	3,565
2006	3,163	3,079	3,176
2007	3,296	3,349	3,281
2008	3,480	3,510	3,428
2009	3,565	3,547	3,495
2010	3,344	3,322	3,320
2012 Forecast	3,468		3,418

[1]Fitted and forecast Gas Supply degree days are calculated using the following regression equation:

Gas Supply degree days = 665.9574+0.7936(Environment Canada degree days)

AVERAGE USE FORECASTING MODEL & ECONOMIC ASSUMPTIONS

1. The purpose of this evidence is to present the forecasting methodology used to forecast average use for Rate 1 revenue class 20 and Rate 6 revenue classes 12, 48 and 73[1]. Rate 1 is the Company's residential rate class while Rate 6 is the Company's small apartment, commercial, and industrial rate class. The forecasting methodology for the other revenue classes in Rate 1 and Rate 6 are very similar to the models presented in this exhibit.

2. In 2012[2] revenue class 20 is forecast to comprise 86% of Rate 1 volumes while revenue classes 12, 48, and 73 are forecast to collectively comprise 90% of Rate 6 volumes. Volumes for the remaining revenue classes in Rate 1 are forecast to comprise 14% of Rate 1 volumes while the remaining revenue classes in Rate 6 are forecast to comprise 10% of Rate 6 volumes.

3. For the 2001 budget the Company moved to a more objective forecasting methodology in order to address the Board's concern with the under-forecasting bias attributed to the grassroots forecasting process as discussed in RP-2001-0001 Reasons for Decisions. This forecasting methodology would remove systematic or subjective bias by developing regression models to forecast average use for the Company's Rate 1 general service customers and Rate 6 general service customers. The econometric methodology has been in place since 2001 and the

[1] Rate 1 is comprised of: revenue class 10 - residential heating, revenue class 20 - residential space heating and water heating, revenue class 50 - space heating, water heating and pool heating, revenue class 60 – residential general service and revenue class 61 – residential water heating. Rate 6 is comprised of: revenue class 12 – apartment heating and other uses, revenue class 48 commercial heating and other uses, revenue class 73 industrial heating and other uses, revenue class 79 commercial general service, revenue class 83 – industrial general service, revenue class 86 – apartment general service, revenue class 90 – commercial air conditioning and space heating.
[2] All data, models and forecasts are calculated using a calendar (i.e. December) year end.

forecasts produced and accepted in settlement proposals and Board decisions since. As shown in Tables 1 to 3, 5, and 8 below, the models exhibit a high R^2 and low Root Mean Squared Percentage Error ("RMSPE") indicating the regression model is a good predictor of average use.

4. The year-over-year growth rates in average use for all revenue classes are used to compute the average use forecast for Rate 1 and Rate 6. Factors influencing overall average use include new customers (both new construction and replacement customers), the timing of new customer additions to the system, rate migration, gas prices, economic conditions and the Company's DSM programs. Refer to Exhibit C, Tab 2, Schedule 1 for a summary of the Company's gas volume budget.

5. Average use is defined as gas volume per unlock customer. The econometric models presented here utilize historical data and relationships to derive a top down forecast of average use. The models presented in the exhibit incorporate updated driver variables and historical data obtained from federal and provincial statistical agencies and the Company's database. Maintaining an econometric model is an ongoing process, consequently, the models must be monitored and refined to ensure they are valid and produce accurate forecasts of general service average use.

<u>Error Correction Model</u>

6. The Company uses the Error Correction Model ("ECM") to forecast the average use for Rate 1 and Rate 6. The Error Correction Model and the two step estimation procedure are described more fully in Engle and Granger (1987).[3] The error correction model uses the concept of cointegration or long-run association between

[3] Engle, R.F. and Granger, C.W.J (1987), "Cointegration and Error Correction: Representation, Estimation and Testing," *Econometrica*, Vol. 55, No.2.

variables. In other words, variables hypothesized to be linked by some theoretical economic relationship should not diverge from each other in the long run. Such variables may drift apart in the short run, however, if they were to diverge without bound, an equilibrium relationship among such variables could not be said to exist. The ECM methodology has been used extensively in the energy field for modeling electricity sales[4] and natural gas prices[5].

7. The major difference between the ECM approach and the standard dynamic single-equation model is the ECM approach explicitly takes into account both long-run equilibrium and short-run dynamic relationships in the determination of average use. It is known that economic theory can provide useful information about the variables relevant in the long-run. However, it is relatively silent on the short-run dynamics between variables. The ECM approach allows the historical data to determine the lag structures and short run dynamics.

8. The estimated models are used to generate a normalized forecast of average use. The main purpose of the normalized forecast is to compute average use such that the weather impact has been taken out. Using the estimated coefficients, weather normalized average use data are obtained by replacing actual degree days in the model with budgeted degree days for 2012.

<u>Average Use Forecasting Methodology</u>

9. The model's specification is based on an objective criterion: to minimize both in-sample and out-of-sample forecast error. The discrepancy between actual average use and the model's forecast can be segregated into three major sources of

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[4] Engle, R.F., Granger, C.W.J. and Hallman, J.J. (1989), "Merging Short- and Long-Run Forecasts: An Application to Monthly Electricity Sales Forecasting," *Journal of Econometrics*, Vol.40.
[5] Bopp, A.E. (1990), "An Analytical Approach to Forecasting Natural Gas Prices," *AGA Forecasting Review*: American Gas Association.

uncertainty: (1) model specification, (2) forecast error from the driver variables used in the model and (3) unexpected shocks or structural breaks. Sources (2) and (3) are not within the Company's control and will inevitably occur regardless of which forecasting methodology is adopted. Therefore the objective of the modeling procedure, described below, is to minimize the controllable source of error, the model's specification.

10. The main criteria for assessing the model's predictive ability is the model's forecast accuracy. A comparison of actual un-normalized average use versus the forecasts produced by the model is used to assess predictive ability. Forecast accuracy is measured using both in-sample and out-of-sample average percent variance ("MPE") and RMSPE. In-sample, or ex-post, means that the estimated model incorporates the entire sample, in this case 1985 to 2010. Out-of-sample, or ex-ante, means that the model incorporates only a portion of the sample, in this case 1985 to 2008. Forecasts of average use are produced under both approaches and measured against actual average use from 2009 to 2010 quantitatively via MPE and RMSPE. A two year "hold out" sample is used to compute the in-sample and out-of-sample forecast accuracy statistics since the forecasting horizon for budgeting purposes is two years. Table 1 presents the forecast accuracy statistics for Rate 1 and Rate 6. The smaller the MPE and RMSPE, the better model's forecast performance.

Witnesses: S. Murray
H. Sayyan

TABLE 1
FORECAST ERRORS - PERCENT VARIANCE & ROOT MEAN SQUARED PERCENTAGE ERROR

Col 1.	Col 2.	Col 3.
Forecast Error Method	Rate 1	Rate 6
In-Sample % Variance (2 Years)	-0.12%	-0.50%
In-Sample RMSPE (2 Years)	0.19%	0.99%
Out-of-Sample % Variance (2 Years)	1.59%	-7.65%
Out-of-Sample RMSPE (2 Years)	1.88%	8.66%

$$MPE = \frac{1}{N}\sum_{i=1}^{N}\left(\frac{Forecast_i - Actual_i}{Actual_i}\right)$$

$$RMSPE = \sqrt{\frac{1}{N}\sum_{i=1}^{N}\left(\frac{Forecast_i - Actual_i}{Actual_i}\right)^2}$$

11. Consistent with Commitment Issue 1.1 from the RP-2000-0040 Settlement Agreement, Tables 2 and 3 report the results that the models would generate using actual data to allow parties to compare results to the prior year's forecast. Tables 2 and 3 show the results that the models would have produced had all actual data been available at the time the forecast was produced. The tables are not updated for 2004 since there are no Board approved average use forecasts for this particular test year. In order to compare the variance between actual and Board approved average use on the same basis, the actual results for each year have been normalized to the corresponding Board approved degree days for each respective test year. The results in Tables 2 and 3 show the regression model is a good predictor of general service average use.

Witnesses: S. Murray
H. Sayyan

TABLE 2

RATE 1 IN-SAMPLE FORECAST COMPARISON

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Fiscal Year	Actual Normalized Average Use Per Customer	Board Approved Normalized Average Use Per Customer[1,3]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer	Model's Normalized Average Use Per Customer[2]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer
	(m3)	m(3)	(2-3)	100*((2-3)/3)	(m3)	(2-6)	100*((2-6)/6)
2001	3,014	3,044	(30)	-1.0%	3,022	(8)	-0.26%
2002	2,980	2,970	10	0.3%	2,963	17	0.57%
2003	2,877	2,892	(15)	-0.5%	2,897	(20)	-0.69%
2004	2,843	n/a	n/a	n/a	2,864	(21)	-0.73%
2005	2,890	2,953	(63)	-2.1%	2,929	(39)	-1.33%
2006	2,796	2,850	(54)	-1.9%	2,816	(20)	-0.71%
2007	2,726	2,687	39	1.5%	2,695	31	1.15%
2008	2,636	2,647	(11)	-0.4%	2,611	25	0.97%
2009	2,616	2,637	(21)	-0.8%	2,623	(6)	-0.24%
2010	2,579	2,622	(43)	-1.6%	2,550	29	1.15%

[1]Board approved normalized average use from RP-2000-0040, RP-2001-0032, RP-2002-0133, RP-2003-0203, EB-2005-000, EB-2006-0034, EB-2007-0615, EB-2008-0219 and EB-2009-0172 for 2001, 2002, 2003, 2005, 2006, 2007, 2008, 2009 and 2010 respectively.

[2]Model's normalized average use is generated by running the model using actual data and driver variable information.

[3]There is no Board approved normalized average use for 2004.

TABLE 3
RATE 6 IN-SAMPLE FORECAST COMPARISON

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Fiscal Year	Actual Normalized Average Use Per Customer	Board Approved Normalized Average Use Per Customer[1,3]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer	Model's Normalized Average Use Per Customer[2]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer
	(m3)	m(3)	(2-3)	100*((2-3)/3)	(m3)	(2-6)	100*((2-6)/6)
2001	22,510	22,643	(133)	-0.6%	22,706	(196)	-0.86%
2002	22,097	22,125	(28)	-0.1%	21,957	140	0.64%
2003	21,593	21,685	(92)	-0.4%	21,613	(20)	-0.09%
2004	21,472	n/a	n/a	n/a	21,377	95	0.44%
2005	22,241	22,507	(266)	-1.2%	22,334	(93)	-0.42%
2006	22,272	21,999	273	1.2%	22,149	123	0.55%
2007	22,783	21,010	1773	8.4%	22,973	(190)	-0.83%
2008	24,869	24,204	665	2.7%	25,273	(404)	-1.60%
2009	27,654	28,165	(512)	-1.8%	27,875	(222)	-0.79%
2010	29,106	27,949	1157	4.1%	29,691	(585)	-1.97%

[1]Board approved normalized average use from RP-2000-0040, RP-2001-0032, RP-2002-0133, RP-2003-0203, EB-2005-000, EB-2006-0034, EB-2007-0615, EB-2008-0219 and EB-2009-0172 for 2001, 2002, 2003, 2005, 2006, 2007, 2008, 2009 and 2010 respectively.

[2]Model's normalized average use is generated by running the model using actual data and driver variable information.

[3]There is no Board approved normalized average use for 2004.

Witnesses: S. Murray
H. Sayyan

12. The primary goal of the average use forecast is to be accurate and objective. Ideally, the forecast error should be small in magnitude and distributed in a random fashion. Although the forecast errors in Tables 1, 2, and 3 are small in magnitude, forecast accuracy is conditional on driver variable forecast accuracy and the absence of any structural break between the historical period and the upcoming forecast period. Consequently, besides testing forecast accuracy, the models were subjected to a battery of specification tests. These tests were run on the model to check for incorrect functional forms, parameter instability, structural breaks, omitted variables and randomness of residuals. Overall the models have been thoroughly tested and are statistically valid. The following diagnostic tests were run on each model (results are shown in Tables 6 and 9):

Breusch-Godfrey Serial Correlation LM Test[6]

This test is used to test for autocorrelation in the residuals. Autocorrelation occurs when disturbances in a regression equation are serially correlated. The test is set up as follows:

Null Hypothesis: No serial correlation

Alternative Hypothesis: Serial correlation

ARCH Test

This test is used to test for autoregressive conditional heteroskedasticity (ARCH). ARCH occurs when the variance of disturbances in a regression equation are not constant and are serially correlated. The test is set up as follows:

Null Hypothesis: No ARCH

Alternative Hypothesis: ARCH

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[6] The Durbin-Watson test is not used since it is not valid when there are lagged dependent variables in a regression equation. The Durbin Watson test is biased toward the finding of no serial correlation if there are lagged values of the dependent variable in the regression equation.

Chow Forecast Test

This test is used to test for stability of a regression model. A regression model is not stable if the estimated coefficients change (and consequently the model's predictions) when estimated over various sample ranges. The test is set up as follows:

Null Hypothesis: No structural change

Alternative Hypothesis: Structural change

Ramsey RESET Test

This is a general test which tests for omitted variables, incorrect functional form and correlation between the independent variables and disturbances. The test is set up as follows:

Null Hypothesis: Normally distributed disturbances (zero mean, constant variance)

Alternative Hypothesis: Non-normally distributed disturbances (non-zero mean, constant variance)

13. The remainder of this section shows the following: Tables 4 and 7 show the mnemonics of the models; Tables 5 and 8 show the regression equations for each model; Tables 6 and 9 show the results of the diagnostic tests run on the models.

TABLE 4 - RATE 1 MODEL MNEMONICS

Mnemonic	Definition
C	Constant Term
LOG(X)	Logarithm of Variable X
DLOG(X)	$LOG(X_t) - LOG(X_{t-1})$, First Difference of Logarithm of Variable X
CDD, EDD, NDD	Balance Point Heating Degree Days for Central, Eastern and Niagara Weather Zones
MET20VINT	Vintage Variable for the Metro Region, Central Weather Zone
WES20VINT	Vintage Variable for the Western Region, Central Weather Zone
CEN20VINT	Vintage Variable for the Central Region, Central Weather Zone
NOR20VINT	Vintage Variable for the Northern Region, Central Weather Zone
ERC20VINT	Vintage Variable for the Eastern Weather Zone
NRC20VINT	Vintage Variable for the Niagara Weather Zone
REALCRCRPG	Real Residential Natural Gas Price for the Central Weather Zone
REALERCRPG	Real Residential Natural Gas Price for the Eastern Weather Zone
REALNRCRPG	Real Residential Natural Gas Price for the Niagara Weather Zone
TIME	Time Trend
DUM2008-DUM2009	Dummy Variables for Recession Impact
CENTEMP	Central Weather Zone Employment
AR(1)	First-order Autoregressive Process Term
ECM_Region	Error Correction Term for Each Region

TABLE 5 - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Metro Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.46	6.46	0.00
LOG(CDD)	0.72	15.18	0.00
LOG(REALCRCRPG)	-0.03	-1.60	0.13
LOG(MET20VINT)	0.60	9.66	0.00
DUM2008	-0.06	-4.95	0.00
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.02		
F-statistic	294.40		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.03	0.98
DLOG(CDD)	0.75	26.12	0.00
DLOG(MET20VINT)	0.73	1.86	0.08
DUM2008	-0.01	-1.70	0.10
ECM_MET20(-1)	-0.34	-1.85	0.08
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	193.48		0.00

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.81	0.93	0.36
LOG(CDD)	0.72	20.00	0.00
LOG(REALCRCRPG)	-0.09	-5.86	0.00
LOG(WES20VINT)	0.26	5.36	0.00
LOG(CENTEMP)	0.18	1.90	0.07
DUM2008	-0.06	-6.41	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	395.37		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-2.35	0.03
DLOG(CDD)	0.72	36.58	0.00
DLOG(REALCRCRPG)	-0.08	-5.09	0.00
DUM2008	-0.02	-3.48	0.00
ECM_WES20(-1)	-0.72	-3.98	0.00
R-squared	0.99		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	362.16		0.00

Central Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.05	-0.06	0.96
LOG(CDD)	0.73	17.79	0.00
LOG(REALCRCRPG)	-0.07	-3.84	0.00
LOG(CEN20VINT)	0.34	8.69	0.00
LOG(CENTEMP)	0.27	3.05	0.01
DUM2008	-0.06	-6.01	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	365.28		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.26	0.80
DLOG(CDD)	0.71	21.98	0.00
DLOG(REALCRCRPG)	-0.05	-1.98	0.06
DLOG(CEN20VINT)	0.25	1.67	0.11
DUM2008	-0.02	-2.32	0.03
ECM_CEN20(-1)	-0.89	-3.45	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	110.33		0.00

Witnesses: S. Murray
H. Sayyan

TABLE 5 CONTINUED - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Northern Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.77	0.89	0.39
LOG(CDD)	0.71	18.82	0.00
LOG(REALCRCRPG)	-0.11	-6.02	0.00
LOG(NOR20VINT)	0.27	7.65	0.00
LOG(CENTEMP)	0.20	2.14	0.04
DUM2009	-0.06	-5.65	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	517.12		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	1.21	0.24
DLOG(CDD)	0.73	27.60	0.00
DLOG(REALCRCRPG)	-0.06	-2.32	0.03
DLOG(NOR20VINT)	0.27	3.24	0.00
DUM2009	-0.03	-4.40	0.00
AR(1)	-0.64	-2.83	0.01
ECM_NOR20(-1)	-0.65	-2.99	0.01
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	132.33		0.00

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.40	3.87	0.00
LOG(EDD)	0.80	18.33	0.00
LOG(REALERCRPG)	-0.05	-3.18	0.00
LOG(ERC20VINT)	0.24	15.53	0.00
DUM2008	-0.06	-5.71	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	478.47		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.76	0.01
DLOG(EDD)	0.79	23.33	0.00
DLOG(REALERCRPG)	-0.06	-2.21	0.04
DUM2008	-0.02	-2.07	0.05
ECM_ERC20(-1)	-0.69	-2.83	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	149.72		0.00

Niagara Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.31	4.41	0.00
LOG(NDD)	0.71	10.94	0.00
LOG(TIME)	-0.02	-1.09	0.29
LOG(REALNRCRPG)	-0.06	-1.62	0.12
LOG(NRC20VINT)	0.61	2.89	0.01
DUM2008	-0.09	-4.30	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	179.44		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-3.18	0.00
DLOG(NDD)	0.72	23.11	0.00
DLOG(REALNRCRPG)	-0.05	-1.73	0.10
DUM2008	-0.03	-2.69	0.01
ECM_NRC20(-1)	-0.46	-2.77	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	147.00		0.00

TABLE 6 - RATE 1

Model Diagnostic Tests

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Test		Metro Region	Western Region	Central Region	Northern Region	Eastern Weather Zone	Niagara Weather Zone
Breusch-Godfrey Serial Correlation LM Test	Test Statistic	0.45	0.51	0.44	0.00	1.53	0.02
	P Value	0.50	0.48	0.51	0.95	0.22	0.90
ARCH Test	Test Statistic	0.27	0.35	0.84	3.40	0.04	0.02
	P Value	0.61	0.55	0.36	0.07	0.83	0.89
Chow Forecast Test: Forecast from 2009 to 2009	Test Statistic	0.00	0.04	0.01	2.81	0.04	0.04
	P Value	0.97	0.84	0.91	0.11	0.85	0.84
Ramsey RESET Test	Test Statistic	1.55	0.42	0.48	0.53	0.78	0.06
	P Value	0.23	0.53	0.50	0.48	0.39	0.82

TABLE 7 - RATE 6 MODEL MNEMONICS

Mnemonic	Definition
C	Constant Term
LOG(X)	Logarithm of Variable X
DLOG(X)	$LOG(X_t)$ - $LOG(X_{t-1})$, First Difference of Logarithm of Variable X
CDD, EDD, NDD	Balance Point Heating Degree Days for Central, Eastern and Niagara Weather Zones
CENTEMP	Central Weather Zone Employment
EASTEMP	Eastern Weather Zone Employment
NIAGEMP	Niagara Weather Zone Employment
REALCRCCPG	Real Commercial Gas Price for the Central Weather Zone
REALERCCPG	Real Commercial Gas Price for the Eastern Weather Zone
REALNRCCPG	Real Natural Gas Price for the Niagara Weather Zone
ONTGDP	Ontario Real Gross Domestic Product
MANUFACTURING	Ontario Manufacturing Industry Real Domestic Product
CRCCOMVAC	GTA Commercial Vacancy Rate
TIME	Time Trend
DUMRegion	Dummy Variable for Migration Impact
DUMXXXX	Dummy Variable for the Break in the Year XXXX
AR(p)	pth-order Autoregressive Process Term
ECM_Region	Error Correction Term for Each Region

Witnesses: S. Murray
H. Sayyan

TABLE 8 - RATE 6 REVENUE CLASS 12 REGRESSION EQUATIONS

Central Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	-0.86	-0.43	0.67
LOG(CDD)	0.67	6.18	0.00
LOG(REALCRCCPG)	-0.12	-1.79	0.09
LOG(CENTEMP)	0.86	4.64	0.00
DUM1996	-0.10	-5.14	0.00
DUMCRC12	0.21	4.87	0.00
AR(4)	-0.42	-1.77	0.10
R-squared	0.97		
Adjusted R-squared	0.95		
S.E. of regression	0.03		
F-statistic	72.284		0.00

Eastern Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	4.26	3.19	0.00
LOG(EDD)	0.56	9.66	0.00
LOG(TIME)	-0.04	-3.55	0.00
LOG(REALERCCPG)	-0.10	-2.30	0.03
LOG(EASTEMP)	0.32	1.79	0.09
DUMERC12	0.22	9.34	0.00
DUM2009	0.07	2.96	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	113.14		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-3.21	0.01
DLOG(EDD)	0.48	9.15	0.00
DLOG(REALERCCPG)	-0.13	-3.64	0.00
DLOG(EASTEMP)	0.84	3.83	0.00
DUMERC12	0.15	8.56	0.00
DUM2010	-0.14	-3.14	0.01
ECM_ERC12(-1)	-0.85	-2.86	0.01
AR(2)	-0.84	-2.84	0.01
R-squared	0.95		
Adjusted R-squared	0.92		
S.E. of regression	0.02		
F-statistic	38.02		0.00

Niagara Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	3.33	3.47	0.00
LOG(NDD)	0.64	10.47	0.00
LOG(TIME)	-0.03	-4.38	0.00
LOG(REALNRCCPG)	-0.07	-2.96	0.01
LOG(NIAGEMP)	0.44	3.69	0.00
DUMNRC12	-0.08	-7.36	0.00
AR(1)	-0.78	-3.60	0.00
R-squared	0.86		
Adjusted R-squared	0.81		
S.E. of regression	0.02		
F-statistic	17.81		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-1.58	0.13
DLOG(NDD)	0.57	13.39	0.00
DLOG(NIAGEMP)	0.38	3.95	0.00
DLOG(REALNRCCPG)	-0.04	-1.45	0.17
DUMNRC12	-0.05	-5.40	0.00
DUM2010	0.15	5.90	0.00
AR(1)	-0.67	-2.98	0.01
ECM_NRC12(-1)	-0.71	-4.47	0.00
R-squared	0.94		
Adjusted R-squared	0.92		
S.E. of regression	0.02		
F-statistic	38.39		0.00

TABLE 8 CONTINUED - RATE 6 REVENUE CLASS 48 REGRESSION EQUATIONS

Central Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.07	0.08	0.94
LOG(CDD)	0.87	14.81	0.00
LOG(TIME)	-0.12	-8.91	0.00
LOG(CRCCOMVAC)	-0.07	-4.37	0.00
LOG(ONTGDP)	0.26	4.20	0.00
DUM2009	0.09	6.36	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	129.67		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.14	0.89
DLOG(CDD)	0.87	29.85	0.00
DLOG(TIME)	-0.06	-3.47	0.00
DLOG(CRCCOMVAC)	-0.06	-5.01	0.00
DUM2009	0.04	4.17	0.00
ECM_CRC48(-1)	-0.84	-5.35	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	181.05		0.00

Eastern Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.67	1.78	0.09
LOG(EDD)	0.74	10.41	0.00
LOG(TIME)	-0.16	-14.40	0.00
LOG(ONTGDP)	0.20	4.09	0.00
DUMERC48	0.10	5.67	0.00
DUM2010	0.14	4.95	0.00
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	143.43		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.16	0.87
DLOG(EDD)	0.79	19.67	0.00
DLOG(TIME)	-0.10	-4.45	0.00
DUMERC48	0.04	3.48	0.00
DUM2010	0.10	4.72	0.00
ECM_ERC48(-1)	-0.97	-5.35	0.00
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	0.02		
F-statistic	90.57		0.00

Niagara Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.82	-0.52	0.61
LOG(NDD)	0.70	11.61	0.00
LOG(TIME)	-0.09	-4.62	0.00
LOG(REALNRCCPG)	-0.17	-4.23	0.00
LOG(ONTGDP)	0.39	3.59	0.00
DUM2009	0.11	5.01	0.00
DUM2010	-0.12	-4.09	0.00
R-squared	0.93		
Adjusted R-squared	0.91		
S.E. of regression	0.02		
F-statistic	42.02		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.09	0.05
DLOG(NDD)	0.72	16.51	0.00
DLOG(ONTGDP)	0.37	2.19	0.04
DUM2009	0.15	6.30	0.00
DUM2010	-0.24	-7.49	0.00
ECM_NRC48(-1)	-0.82	-3.34	0.00
R-squared	0.96		
Adjusted R-squared	0.94		
S.E. of regression	0.02		
F-statistic	83.47		0.00

Witnesses: S. Murray
H. Sayyan

TABLE 8 CONTINUED - RATE 6 REVENUE CLASS 73 REGRESSION EQUATIONS

Central Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	4.23	1.77	0.09
LOG(CDD)	0.26	1.54	0.14
LOG(TIME)	-0.16	-5.06	0.00
LOG(ONTGDP)	0.39	3.14	0.01
DUM2008	0.43	11.71	0.00
AR(1)	-0.27	-0.99	0.33
R-squared	0.87		
Adjusted R-squared	0.84		
S.E. of regression	0.06		0.00
F-statistic	26.066		

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.02	-1.84	0.08
DLOG(CDD)	0.49	5.51	0.00
DLOG(ONTGDP)	0.51	1.78	0.09
DUM2008	0.24	5.70	0.00
DUM2009	-0.10	-1.68	0.11
ECM_CRC73(-1)	-0.49	-2.16	0.04
R-squared	0.86		
Adjusted R-squared	0.82		
S.E. of regression	0.04		
F-statistic	22.44		0.00

Eastern Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-117,954.60	-1.00	0.33
EDD	0.21	0.01	0.99
TIME	-5,462.74	-3.95	0.00
EASTEMP	518.20	2.83	0.01
DUM2003	78,497.98	3.66	0.00
DUM2004	-169,860.70	-6.35	0.00
DUMERC73	96,778.38	5.92	0.00
R-squared	0.87		
Adjusted R-squared	0.83		
S.E. of regression	18,567.14		
F-statistic	22.07		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-1,998.48	-0.32	0.75
D(EDD)	12.15	0.66	0.52
D(EASTEMP)	665.58	1.40	0.18
DUM2003	69,862.70	2.67	0.02
DUM2004	-239,557.20	-6.39	0.00
DUMERC73	31,240.88	2.05	0.06
ECM_ERC73(-1)	-0.79	-1.98	0.06
R-squared	0.84		
Adjusted R-squared	0.79		
S.E. of regression	22,917.07		
F-statistic	15.64		0.00

Niagara Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-7.47	-1.51	0.15
LOG(NDD)	0.62	1.89	0.08
LOG(TIME)	-0.19	-3.26	0.00
LOG(REALNRCCPG)	-0.18	-1.51	0.15
LOG(MANUFACTURING)	1.25	3.96	0.00
DUM2002	-0.38	-3.24	0.00
DUMNRC73	0.62	6.06	0.00
DUM2009	0.51	4.37	0.00
R-squared	0.78		
Adjusted R-squared	0.71		
S.E. of regression	0.13		
F-statistic	10.93		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.01	0.99
DLOG(NDD)	0.86	3.70	0.00
DLOG(MANUFACTURING)	0.69	1.83	0.08
DUM2002	-0.40	-3.32	0.00
DUMNRC73	0.28	4.13	0.00
ECM_NRC73(-1)	-0.51	-1.96	0.07
R-squared	0.76		
Adjusted R-squared	0.70		
S.E. of regression	0.11		
F-statistic	12.13		0.00

TABLE 9-RATE 6
Model Diagnostic Tests

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.	Col 9.	Col 10.	Col 11.
		Revenue Class 12 (Apartment) Model Diagnostic Tests			**Revenue Class 48 (Commercial) Model Diagnostic Tests**			**Revenue Class 73 (Industrial) Model Diagnostic Tests**		
Test		Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone
Breusch-Godfrey Serial Correlation LM Test	Test Statistic	1.45	2.37	0.14	0.71	1.62	0.05	0.02	0.41	0.13
	P Value	0.23	0.12	0.71	0.40	0.20	0.83	0.89	0.52	0.72
ARCH Test	Test Statistic	0.08	0.16	0.29	0.04	0.18	0.26	1.57	0.07	0.62
	P Value	0.77	0.69	0.59	0.84	0.67	0.61	0.21	0.80	0.43
Chow Forecast Test: Forecast from 2010 to 2010	Test Statistic	2.14	7.43*	34.80*	2.78	22.24*	56.16*	2.86	0.00	1.23
	P Value	0.17	0.02	0.00	0.11	0.00	0.00	0.11	0.95	0.28
Ramsey RESET Test	Test Statistic	2.05	1.21	0.79	0.61	2.59	0.07	0.45	0.07	0.64
	P Value	0.17	0.29	0.39	0.44	0.13	0.79	0.51	0.80	0.43

*without dum2010

14. Driver variable assumptions are presented in Table 10 in year over year growth rates. Major driver variables in the models are balance point heating degree days adjusted for billing cycles, vintage, time trend, real natural gas prices, and economic variables. The driver variable assumptions are based on economic assumptions from the Economic Outlook, Spring 2011.

15. Natural gas prices have an important impact on average use. Sharp increases typically have two effects. Firstly, they influence customers' fuel use habits, for example, the lowering of thermostat settings. Secondly, price increases likely factor in customers' decision-making around the purchase of more efficient furnaces and other appliances. In addition, homeowners may also respond by retrofitting older residences in order to reduce energy consumption. In the models, real natural gas prices are used. The Consumer Price Index ("CPI") is used to convert nominal gas prices to real gas prices. Nominal energy price forecasts are based on the Fekete's Henry Hub price forecast produced in April 2011.

16. A linear time trend is used as a proxy measure for energy conservation. However, a linear time trend only reflects constant annual changes in appliance efficiency; it will not be able to reflect the time varying impact of new residential construction on appliance efficiency. Consequently, a vintage variable serves as either a supplementary or complementary variable to the time trend in the model.

17. The vintage variable (for revenue class 20 only) is employed as a proxy measure of gas space heating and gas water heating efficiency gains and residential thermal efficiency. Newer homes with improved thermal envelope characteristics and older homes adding insulation and storm windows/doors reduce the typical amount of gas needed for space heating. Residential thermal efficiency will continue to improve as newer, better-insulated residences account for a larger portion of the housing stock. The vintage variable captures the impact of both furnace efficiency and new home thermal efficiency on average use.

18. Vintage is defined as the fiscal year in which the customer became a customer (new gas service main date) and is not based on the age of the building. This data includes both new construction and conversion customer additions. As space heating efficiency gains have a greater impact on average use than thermal improvements to homes, customers by vintage is a better variable than age of the building in terms of explaining the percentage decline in residential average use.

19. An illustration of the vintage ratio for 1992 follows:

$$V_{1992} = \frac{\sum_{y=1987}^{1991} V_y}{\sum_{yy=1987}^{1992} V_{yy}}$$ where V denotes vintage.

Witnesses: S. Murray
H. Sayyan

20. Fiscal 1991 is used as the reference year for the vintage ratio since the Energy Efficiency Act prohibited selling of the conventional low-efficiency furnace in January 1992.[7] Consequently, this ratio will capture the increasing market share of both mid-efficiency and high-efficiency furnaces at the expense of declining market share of conventional furnaces over time. Table 10 shows that regions with stronger new construction additions, such as Western and Northern, experience a sharper decline in the ratio than established regions like Metro. As more new customers are added to the revenue class the declining ratio leads to lower average use over time. Thus the sign of this variable's coefficient is positive.

21. Economic variables such as employment, vacancy rates, and gross domestic product can impact demand for new gas appliances as well as impact demand for natural gas for space heating and manufacturing processes. Stronger employment and demand for products both domestically and abroad will generally increase natural gas demand.

[7] During the 1970s natural gas furnaces averages about 65% Annual fuel Utilization Efficiency ("AFUE"). The Energy Efficiency Act imposed 78 % AFUE as a minimum for gas furnaces manufactured after January 1, 1992.

TABLE-10
Economic Outlook

CANADA & U.S.

CALENDAR YEAR	2006	2007	2008	2009	2010	2011F	2012F
REAL GDP (% CHANGE)							
CANADA	2.8	2.2	0.5	-2.5	3.1	2.9	2.7
U.S.	2.7	1.9	0.0	-2.6	2.8	2.9	3.3
REAL EXPORTS (% CHANGE)	0.6	1.2	-4.6	-14.2	6.4	7.6	6.5
REAL IMPORTS (% CHANGE)	4.9	5.9	1.2	-13.9	13.4	7.4	5.4
HOUSING STARTS (000's)	227.4	228.3	211.1	149.1	189.9	176.1	179.3
UNEMPLOYMENT RATE (%)	6.3	6.0	6.1	8.3	8.0	7.6	7.3
EMPLOYMENT GROWTH (% CHANGE)	1.8	2.4	1.7	-1.6	1.4	1.6	1.5
CONSUMER PRICES (% CHANGE)							
CANADA	2.0	2.1	2.4	0.3	1.8	2.6	2.1
U.S.	3.2	2.8	3.8	-0.4	1.6	2.4	2.0

TABLE-10 CONTINUED
Economic Outlook

ONTARIO

CALENDAR YEAR	2006	2007	2008	2009	2010	2011F	2012F
REAL GDP (% CHANGE)	2.4	2.0	-0.9	-3.6	2.8	2.6	2.5
REAL MANUFACTURING OUTPUT (% CHANGE)	-2.1	-4.2	-10.3	-15.0	10.1	4.0	3.1
HOUSING STARTS (000's)	73.4	68.1	75.1	50.4	60.4	57.0	59.6
UNEMPLOYMENT RATE (%)	6.3	6.4	6.5	9.0	8.6	8.3	7.9
EMPLOYMENT GROWTH (% CHANGE)	1.2	1.8	1.5	-2.4	1.6	1.6	1.6
CONSUMER PRICES (% CHANGE)	1.8	1.8	2.3	0.4	2.4	2.6	2.1
RETAIL SALES (% CHANGE)	4.1	3.9	3.5	-2.4	4.9	4.6	4.0
WAGE RATE (% CHANGE)	5.1	4.6	2.9	-0.9	2.8	5.3	4.7
REAL RESIDENTIAL NATURAL GAS PRICE (% CHANGE)	8.9	-11.4	1.5	-17.8	-13.2	-11.2	5.2
REAL COMMERCIAL NATURAL GAS PRICE (% CHANGE)	10.0	-12.7	1.6	-19.8	-14.5	-12.6	5.9

TABLE-10 CONTINUED
Economic Outlook

REGIONS

CALENDAR YEAR	2006	2007	2008	2009	2010	2011F	2012F
GTA							
HOUSING STARTS (000's)	38.8	35.7	42.4	25.8	30.9	29.4	30.8
SINGLES	15.9	16.1	11.9	8.4	12.0	9.0	11.3
MULTIPLES	22.9	19.7	30.4	17.4	18.9	20.4	19.5
CONSUMER PRICES (% CHANGE)	1.6	1.9	2.4	0.5	2.5	2.2	1.9
UNEMPLOYMENT RATE (%)	6.3	6.5	6.6	9.0	9.1	8.1	8.1
EMPLOYMENT GROWTH (% CHANGE)	1.5	2.2	1.8	-1.7	2.1	1.9	2.1
COMMERCIAL VACANCY RATE (%)	7.3	6.3	5.4	6.9	7.9	7.4	7.4
INDUSTRIAL VACANCY RATE (%)	5.1	5.4	5.9	7.0	6.5	6.3	6.3
VINTAGE METRO REGION CENTRAL WEATHER ZONE (% CHANGE)	-1.1	-1.8	-0.9	-0.9	-1.1	-1.0	-1.0
VINTAGE WESTERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-2.5	-2.7	-2.1	-2.1	-3.3	-2.9	-2.8
VINTAGE CENTRAL REGION CENTRAL WEATHER ZONE (% CHANGE)	-3.8	-3.1	-2.7	-2.7	-2.9	-2.0	-1.8
VINTAGE NORTHERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-3.8	-3.6	-3.1	-3.1	-5.0	-3.8	-3.6
EASTERN							
HOUSING STARTS (000's)	6.1	6.8	7.2	6.0	6.6	6.3	6.6
SINGLES	2.7	3.1	3.1	2.6	2.4	2.5	2.8
MULTIPLES	3.4	3.6	4.1	3.4	4.2	3.8	3.8
CONSUMER PRICES (% CHANGE)	1.7	1.9	2.2	0.6	2.5	2.4	2.0
UNEMPLOYMENT RATE (%)	5.5	5.6	4.9	6.0	6.9	6.4	6.0
EMPLOYMENT GROWTH (% CHANGE)	3.2	2.0	4.0	-1.4	1.3	1.8	2.2
VINTAGE EASTERN WEATHER ZONE (% CHANGE)	-2.7	-2.8	-3.1	-3.1	-2.0	-2.6	-2.6
NIAGARA							
HOUSING STARTS (000's)	1.4	1.3	1.3	1.0	1.3	1.2	1.3
SINGLES	0.9	0.9	0.8	0.7	0.9	0.8	0.9
MULTIPLES	0.4	0.4	0.5	0.3	0.4	0.4	0.4
UNEMPLOYMENT RATE (%)	6.5	6.8	7.2	10.1	9.6	8.9	8.5
EMPLOYMENT GROWTH (% CHANGE)	-1.5	1.5	2.9	-6.0	1.8	2.0	1.8
VINTAGE NIAGARA WEATHER ZONE (% CHANGE)	-1.2	-1.1	-1.1	-1.1	-0.3	-0.9	-0.8

TABLE-10 CONTINUED
Economic Outlook

INTEREST RATE & EXCHANGE RATE FORECAST

CALENDAR YEAR		2006	2007	2008	2009	2010	2011F	2012F
Canada								
Interest Rates	Overnight Rate	4.06	4.35	2.96	0.40	0.60	1.26	2.47
	Bank Rate	4.31	4.60	3.21	0.65	0.85	1.51	2.72
	Prime Rate	5.81	6.10	4.73	2.40	2.60	3.26	4.47
	1 Year Mortgage Rate	6.28	6.90	6.70	4.02	3.49	3.73	4.59
	3 Year Mortgage Rate	6.45	7.09	6.87	4.57	4.30	4.53	5.30
	5 Year Mortgage Rate	6.66	7.07	7.06	5.63	5.61	5.46	6.06
Money Markets	1 Month T-Bills	3.93	4.05	2.24	0.25	0.47	1.05	2.18
	3 Month T-Bills	4.04	4.12	2.30	0.32	0.58	1.22	2.55
	6 Month T-Bills	4.12	4.26	2.46	0.41	0.76	1.30	2.53
	1 Year T-Bills	4.19	4.32	2.56	0.61	1.07	1.62	2.96
	1 Month Bankers Acceptance	4.13	4.51	3.04	0.42	0.70	1.28	2.42
	3 Month Bankers Acceptance	4.19	4.57	3.08	0.42	0.82	1.36	2.52
	1 Month Commercial Paper	4.15	4.57	3.17	0.65	0.69	1.27	2.40
	3 Month Commercial Paper	4.21	4.63	3.23	0.65	0.79	1.37	2.53
Benchmark Government Bond Yields	2 Year	4.05	4.19	2.62	1.27	1.53	2.06	3.27
	3 Year	4.08	4.21	2.79	1.75	1.83	2.37	3.42
	5Year	4.12	4.22	3.01	2.41	2.45	2.62	3.62
	7 Year	4.16	4.24	3.26	2.67	2.69	2.68	3.61
	10Year	4.22	4.28	3.58	3.29	3.20	3.49	4.28
	30 Year	4.28	4.32	4.05	3.90	3.73	3.87	4.63
United States								
Interest Rates	Federal Funds Rate	5.02	5.00	1.86	0.13	0.13	0.13	1.00
	Prime Rate	7.96	8.05	5.09	3.25	3.25	3.17	3.73
	30 Year Mortgage Rate	6.41	6.34	6.04	5.04	4.69	4.79	5.33
Money Markets	1 Month T-Bills	4.75	4.40	1.29	0.10	0.11	0.09	0.76
	3 Month T-Bills	4.85	4.47	1.39	0.15	0.14	0.12	0.83
	6 Month T-Bills	4.99	4.61	1.66	0.28	0.20	0.18	0.96
	1 Month Non-Financial Commercial Paper	4.97	5.02	1.98	0.18	0.18	0.17	0.71
	3 Month Non-Financial Commercial Paper	4.20	4.99	2.12	0.26	0.23	0.22	0.74
	1 Month Financial Commercial Paper	5.00	5.07	2.38	0.26	0.20	0.19	0.66
	3 Month Financial Commercial Paper	5.06	5.13	2.64	0.42	0.29	0.26	0.70
Treasury Bond Yields	1 Year	4.93	4.52	1.82	0.47	0.32	0.28	0.87
	2 Year	4.82	4.36	2.00	0.96	0.70	0.69	1.56
	3 Year	4.77	4.34	2.24	1.43	1.11	1.14	2.29
	5 Year	4.75	4.43	2.80	2.19	1.93	2.04	3.42
	7 Year	4.76	4.50	3.17	2.81	2.62	2.71	4.06
	10 Year	4.79	4.63	3.67	3.26	3.21	3.53	4.27
	20 Year	4.99	4.91	4.36	4.11	4.03	4.13	5.19
	30 Year	4.87	4.83	4.28	4.07	4.25	4.82	5.39
Exchange Rate	$CDN/$US	1.13	1.07	1.07	1.14	1.03	0.98	1.00
	$US/$CDN	0.88	0.93	0.94	0.88	0.97	1.02	1.00

<u>Risks to the Forecast</u>

22. The impact of customer mix on average use is not static and changes over time. New customers may have different gas use characteristics than existing customers and may be influenced by builder specifications for inclusion/exclusion of new gas appliances. Thus, aggregate average use will be affected even if customers take no actions that could affect their average use. Advances in the future penetration of gas appliances above historical penetration levels implicit in the model could result in increased average use. Conversely, builder specification of non-gas water and/or space heating equipment represents a risk to the forecast as it could result in lower gas consumption than forecast.

23. Use of more efficient water heaters across the franchise area and/or the loss of natural gas water heating to other fuels could result in a permanent decrease in baseload usage and natural gas consumption relative to the forecast.

24. Gas consumption for space heating is very sensitive to thermostat settings. Customers may set their thermostats lower under extremely warm weather like that experienced in 1998, 1999, 2002, 2006, and 2010.

25. Economic activity can impact both demand for appliances and natural gas. If the economy slows more significantly and natural gas prices are higher than indicated in Table 10, average use will decline further.

26. A structural break in the historical estimated relationship between average use and the driver variables will increase forecast risk as will forecast uncertainty in the driver variables.

Conclusion

27. Developing a forecasting model is an ongoing process. The model employed by the Company passes a battery of statistical tests and is valid given current and historical information. Continual evaluation and testing is required, as new information becomes available. The model has been estimated over a volatile period in history – recent years of unexpected warm weather, historically high energy prices and increased energy price volatility. In light of these increasingly volatile economic and weather conditions the model will be evaluated continuously to ensure the continued production of statistically valid and highly accurate results.

Witnesses: S. Murray
H. Sayyan

Y FACTOR POWER GENERATION PROJECTS

1. Enbridge Gas Distribution Inc. ("Enbridge") has one new power generation pipeline project forecast to be in service in 2012, the York Energy Centre Pipeline, which has an expected in service date of November 2011. A small amount of restoration work is forecast to be performed in 2012. Table 1 summarizes capital expenditure and other project details.

2. The contract for the York Energy Centre project was awarded by the Ontario Power Authority in 2008. The facility is natural gas fired and is located within the Enbridge franchise area. On August 28, 2009, Enbridge signed a Rate 125 gas delivery agreement with York Energy Centre LP. A Leave to Construct application (EB-2009-0187) was filed with the Board on September 3, 2009, and Board approval for construction commencement in 2010 was received on April 5, 2010. The York Energy Centre LP project was itself delayed in 2010, thus delaying the Enbridge pipeline build as well. Pipeline construction commenced in December 2010, and first gas delivery is expected in November 2011.

3. The cumulative $6.6 million revenue requirement for all power generation related facilities in service in 2012 which were not included within 2007 base rates, namely the Portlands Energy Centre, the Thorold Cogen, and the York Energy Centre, is shown in Appendix A of this exhibit.

4. Details of the York Energy Centre Pipeline project can be found in Table 1 below.

Witnesses: J. Sim
S. Murray

Table 1

Summary of 2012 Power Generation Related Projects

Facility	York Energy Centre Pipeline Project
Location	Township of King
Forecast Completion Date	November 2011
Pipe Size and Length	NPS 16, 16.7 km
2012 Budget	\$0.1-M [1]
Total Forecast Budget	\$26.9-M [1]

[1] These amounts represent total budgeted project expenditures for the York Energy Centre Pipeline Project. The capitalized amount will be net of the Customer Contribution, which will equal any expenditure above \$26.8-M.

CAPITAL STRUCTURE
POWER GENERATION Y-FACTOR CALCULATION

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

	($000's)	2008	2009	2010	2011	2012
7.	Ontario Utility Income	43.6	(269.3)	(395.6)	(325.0)	(935.6)
8.	Rate base	9,935.3	24,701.5	27,807.6	29,969.3	51,583.8
9.	Indicated rate of return	0.44 %	(1.09)%	(1.42)%	(1.08)%	(1.81)%
10.	(Def.) / suff. in rate of return	(7.14)%	(8.67)%	(9.00)%	(8.66)%	(9.39)%
11.	Net (def.) / suff.	(709.4)	(2,141.6)	(2,502.7)	(2,595.3)	(4,843.7)
12.	Gross (def.) / suff.	(1,066.8)	(3,196.4)	(3,627.1)	(3,617.1)	(6,567.7)

RATE BASE
POWER GENERATION Y-FACTOR CALCULATION

Line No.	($000's)	2008	2009	2010	2011	2012
	Property, plant, and equipment					
1.	Cost or redetermined value	10,065.7	25,569.0	29,841.4	33,237.2	56,691.8
2.	Accumulated depreciation	(130.4)	(867.5)	(2,033.8)	(3,267.9)	(5,108.0)
3.		9,935.3	24,701.5	27,807.6	29,969.3	51,583.8
	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	9,935.3	24,701.5	27,807.6	29,969.3	51,583.8

INCOME
POWER GENERATION Y-FACTOR CALCULATION

($000's)

Line No.		2008	2009	2010	2011	2012
	Revenue					
1.	Gas sales	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-
4.	Other operating revenue	-	-	-	-	-
5.	Other income	-	-	-	-	-
6.	Total revenue	-	-	-	-	-
	Costs and expenses					
7.	Gas costs	-	-	-	-	-
8.	Operation and Maintenance	-	-	-	-	-
9.	Depreciation and amortization	355.6	1,063.8	1,229.3	1,318.7	2,281.2
10.	Municipal and other taxes	45.6	55.3	17.4	-	-
11.	Total costs and expenses	401.2	1,119.1	1,246.7	1,318.7	2,281.2
12.	**Utility income before inc. taxes**	(401.2)	(1,119.1)	(1,246.7)	(1,318.7)	(2,281.2)
	Income taxes					
13.	Excluding interest shield	(297.4)	(488.7)	(469.2)	(618.7)	(745.7)
14.	Tax shield on interest expense	(147.4)	(361.1)	(381.9)	(375.0)	(599.9)
15.	Total income taxes	(444.8)	(849.8)	(851.1)	(993.7)	(1,345.6)
16.	**Ontario utility net income**	43.6	(269.3)	(395.6)	(325.0)	(935.6)

TAXABLE INCOME AND INCOME TAX EXPENSE
POWER GENERATION Y-FACTOR CALCULATION

($000's)

Line No.		2008	2009	2010	2011	2012
1.	Utility income before income taxes	(401.2)	(1,119.1)	(1,246.7)	(1,318.7)	(2,281.2)
	Add Backs					
2.	Depreciation and amortization	355.6	1,063.8	1,229.3	1,318.7	2,281.2
3.	Large corporation tax	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-
6.	Total added back	355.6	1,063.8	1,229.3	1,318.7	2,281.2
7.	Sub total - pre-tax income plus add backs	(45.6)	(55.3)	(17.4)	-	-
	Deductions					
8.	Capital cost allowance - Federal	476.0	1,080.8	1,175.4	1,891.8	2,563.4
9.	Capital cost allowance - Provincial	476.0	1,080.8	1,175.4	1,891.8	2,563.4
10.	Items capitalized for regulatory purposes	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-
13.	Amortization of cumulative eligible capital	366.0	344.9	320.7	298.3	277.4
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-
16.	Total Deductions - Federal	842.0	1,425.7	1,496.1	2,190.1	2,840.8
17.	Total Deductions - Provincial	842.0	1,425.7	1,496.1	2,190.1	2,840.8
18.	Taxable income - Federal	(887.6)	(1,481.0)	(1,513.5)	(2,190.1)	(2,840.8)
19.	Taxable income - Provincial	(887.6)	(1,481.0)	(1,513.5)	(2,190.1)	(2,840.8)
20.	Income tax provision - Federal	(173.1)	(281.4)	(272.4)	(361.4)	(426.1)
21.	Income tax provision - Provincial	(124.3)	(207.3)	(196.8)	(257.3)	(319.6)
22.	Income tax provision - combined	(297.4)	(488.7)	(469.2)	(618.7)	(745.7)
23.	Part V1.1 tax	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(297.4)	(488.7)	(469.2)	(618.7)	(745.7)
	Tax shield on interest expense					
26.	Rate base as adjusted	9,935.3	24,701.5	27,807.6	29,969.3	51,583.8
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	440.1	1,094.3	1,231.9	1,327.6	2,285.2
29.	Combined tax rate	33.500%	33.000%	31.000%	28.250%	26.250%
30.	Income tax credit	(147.4)	(361.1)	(381.9)	(375.0)	(599.9)
31.	**Total income taxes**	(444.8)	(849.8)	(851.1)	(993.7)	(1,345.6)

REVENUE REQUIREMENT
POWER GENERATION Y-FACTOR CALCULATION

($000's)

Line No.		2008	2009	2010	2011	2012
	Cost of capital					
1.	Rate base	9,935.3	24,701.5	27,807.6	29,969.3	51,583.8
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	753.1	1,872.4	2,107.8	2,271.7	3,910.1
	Cost of service					
4.	Gas costs	-	-	-	-	-
5.	Operation and Maintenance	-	-	-	-	-
6.	Depreciation and amortization	355.6	1,063.8	1,229.3	1,318.7	2,281.2
7.	Municipal and other taxes	45.6	55.3	17.4	-	-
8.	Cost of service	401.2	1,119.1	1,246.7	1,318.7	2,281.2
	Misc. & Non-Op. Rev					
9.	Other operating revenue	-	-	-	-	-
10.	Other income	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-
	Income taxes on earnings					
12.	Excluding tax shield	(297.4)	(488.7)	(469.2)	(618.7)	(745.7)
13.	Tax shield provided by interest expense	(147.4)	(361.1)	(381.9)	(375.0)	(599.9)
14.	Income taxes on earnings	(444.8)	(849.8)	(851.1)	(993.7)	(1,345.6)
	Taxes on (def) / suff.					
15.	Gross (def.) / suff.	(1,066.8)	(3,196.4)	(3,627.1)	(3,617.1)	(6,567.7)
16.	Net (def.) / suff.	(709.4)	(2,141.6)	(2,502.7)	(2,595.3)	(4,843.7)
17.	Taxes on (def.) / suff.	357.4	1,054.8	1,124.4	1,021.8	1,724.0
18.	**Revenue requirement**	1,066.9	3,196.5	3,627.8	3,618.5	6,569.7
	Revenue at existing Rates					
19.	Gas sales	0.0	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.1	0.1	0.7	1.4	2.0
23.	Revenue at existing rates	0.1	0.1	0.7	1.4	2.0
24.	**Gross revenue (def.) / suff.**	(1,066.8)	(3,196.4)	(3,627.1)	(3,617.1)	(6,567.7)

Y FACTOR – DSM PROGRAM

1. This evidence supports the Company's Y factor adjustment for DSM related activities. As approved in EB-2007-0615, costs related to ongoing DSM activities are to be recovered within the Incentive Regulation ("IR") distribution revenue based upon amounts approved by the Board in separate DSM proceedings.

2. The DSM Y factor amount included in the 2012 IR distribution revenue formula is $30.9 million, as allowed within the EB-2008-0346 guideline and to be requested in the EB-2011-0295 Natural Gas DSM Plan proceeding. The amount is shown at Exhibit B, Tab 1, Schedule 2, page 1, Column 1, Row 20.

Witness: K. Culbert

Y FACTOR – CIS/CUSTOMER CARE

1. This evidence supports the Company's Y factor adjustments for CIS/Customer Care costs, found within the revenue per customer cap formula evidence at Exhibit B, Tab 1, Schedule 2, page 1.

2. The Company is required to include within its total revenue to be collected in rates determined by the EB-2007-0615 Board approved revenue per customer cap formula, incremental costs related to:

   a. CIS/Customer Care costs that result from the application of the "True Up Template" approved by the Board in the 2008 Final Rate Order, EB-2007-0615, Appendix F, page 1, found at Exhibit E, Tab 2, Schedule 1.

3. The amount recoverable for CIS/Customer Care costs is $99.2 million in the 2012 fiscal year.

Witness: K. Culbert

Y FACTOR – GAS COST AND CARRYING COSTS

1. This evidence supports the Company's Y factor adjustment for 2012 gas cost working cash and gas in storage related carrying costs.

2. The Company is required to include within its total revenue to be collected in rates determined by the EB-2007-0615 Board approved revenue per customer cap formula, incremental costs related to:

   a. Incremental gas costs associated with upstream transportation, storage and supply mix costs relative to the Company's 2012 volumetric forecast. The Company's current 2012 forecast of gas costs to operations is found at Exhibit B, Tab 4, Schedules 1 and 2. Additionally, an adjustment is required to allow for the change in approved rates related to carrying costs of gas in storage and working cash related to gas costs. That is, an adjustment is required to remove the carrying costs associated with the previously approved recovery of the 2011 forecast costs from rates and replace them with the costs associated with the 2012 forecast carrying costs and related working cash that result from the changes inherent in the gas volume budget and associated gas in storage balances. Please refer to Exhibit B, Tab 1, Schedule 2, Appendix A for calculation details.

3. The amount recoverable for carrying costs related to gas in storage and gas cost working cash, for the 2012 fiscal year, is $30.6 million.

Witness: K. Culbert

2012 PENSION FUNDING REQUIREMENT

Background

1. Enbridge Gas Distribution Inc. ("EGD") has historically accounted for pension costs on a flow-through basis where actual cash contributions for pension plan funding are treated as costs and expensed on the Company's income statement. This approach stems from the basis of accounting acceptable for rate-making purposes, as prescribed by the Ontario Energy Board's Uniform System of Accounts for Class "A" Gas Utilities in paragraph 725. Correspondingly these costs form part of the Company's revenue requirement.

2. While Canadian Generally Accepted Accounting Principles ("CGAAP") prescribe the use of accrual accounting for pension costs, as laid out in Section 3461 of the Handbook of the Canadian Institute of Chartered Accountants, special provisions relating to accounting for rate regulated entities have existed in various forms in CGAAP enabling the continued use of the flow-through basis of accounting. EGD adopted the flow-through approach and uses this method when preparing its publicly reporting financial statements.

3. EGD's main pension plan (or "RPP") is a registered pension plan and is subject to the Pension Benefits Act (Ontario) ("PBAO"). The RPP has defined benefit ("DB") and defined contribution ("DC") components. EGD also has a Supplementary Executive Retirement Plan ("SERP") which, although is not a registered pension plan is still managed and accounted for in the same way as the RPP. With respect to asset values or funding status, the evidence primarily addresses the DB component of the RPP as it represents approximately 97% of the plan assets.

Witnesses: S. Kancharla
R. Lei
A. Patel

4. The status of the RPP and SERP are determined with reference to actuarial valuations (“valuations”) conducted by Mercer (Canada) Limited (“Mercer”), the actuarial firm retained by the Company. Mercer conducts a valuation each year.

5. The Financial Services Commission of Ontario (“FSCO”) requires all registered plans to file a valuation at least every three years. EGD last filed its valuation as of December 31, 2009 which indicated a surplus. EGD must file its next valuation as of December 31, 2012 in order to remain compliant. This valuation indicates the funded status of the plan (i.e. the surplus or deficit) and determines the need for contributions to the plan. If the filed report shows a surplus, a contribution holiday is allowed in which contributions do not have to be made until the next filing in three years time. On June 23, 2009 the PBAO introduced a new regulation requiring plan sponsors on a contribution holiday to file an annual actuarial cost certificate with FSCO to prove justification of the contribution holiday. If this cost certificate filing shows a surplus the contribution holiday is continued, however, if the filing shows a deficit, contributions are required to fund the current service cost.

6. The plan surplus or deficit is the net position when comparing the fair-value of the plan assets against the actuarial assessment of the plan obligations as at a given date. An excess of plan assets over plan obligations results in a surplus, while the reverse results in a deficit.

7. In the period prior to incentive regulation (“IR”), EGD was in a surplus[1] and as a result has not had to make contributions to the plan. Furthermore, due to the surplus, EGD’s base year (2007) costs in its current IR term and the corresponding revenue requirement did not include any amounts relating to pension costs. This

[1] Refer to Appendix A for surplus in recent years.

Witnesses: S. Kancharla
R. Lei
A. Patel

has resulted in significant benefits to ratepayers both prior to and during the term of the IR plan. The estimated annual benefit can be defined as the annual employee service cost, which has averaged approximately $13 million annually. Over the past five years alone the benefit to ratepayers has been approximately $83 million[2].

8. This evidence has been written based on a preliminary estimate provided by Mercer in anticipation of the annual cost certificate as of December 31, 2011. A final valuation will be prepared as of December 31, 2011 and will be available early 2012.

Recent Events and their Impact

9. Although EGD has been in a surplus over the years, this surplus has slowly been eroding as the financial markets have not been yielding asset returns in proportion to the growing pension obligations.

10. As seen in Appendix A until 2007, the surplus was sizeable and it seemed that there would be no need for contributions well into the future. However, due to a financial and economic downturn in 2008 which impacted a variety of financial instruments, the large surplus in 2007 turned into a deficit in 2008 under the going concern basis and only recovered slightly in the next few years to a small surplus.

11. In the current year there have been volatile market conditions such that the market value of pension assets has not grown in proportion to the increase in pension liabilities which increases year over year with employee services rendered. By reason of these two factors coupled with only a small surplus as of December 31, 2010, EGD's surplus is expected to be completely eroded by the end

[2] Refer to Mercer's Report "Estimated 2012 Funding Costs – EGD Pension Plans", filed as Appendix B.

of the year such that the fund will be in a deficit position. This deficit position will trigger the requirement for contributions to commence to fund the current service costs for both the RPP and SERP during 2012.

Purpose of this Evidence

12. This evidence has been prepared and filed due to the likelihood that EGD will be required to make annual contributions to the RPP and SERP starting in 2012. Based on Mercer's estimate for the December 31, 2011 valuation, EGD would need to contribute $17.1 million to the RPP and $0.6 million to the SERP for a total contribution of $17.7 million which represents the annual current employee service costs[3].

13. This contribution requirement will translate into an incremental operating cost for EGD. As a result, EGD is seeking recovery of this incremental operating cost as a Z factor in this rate application.

14. It should be noted that the above is an estimate only based on calculations prepared by Mercer as of August 31, 2011. EGD's actual contribution requirement for 2012 will not be determined until the final valuation is conducted by Mercer as of December 31, 2011.

Evaluation of Criteria for Z-factor

15. The following are criteria to be met for Z-factor treatment:
    i. The event must be causally related to an increase/decrease in cost;
    ii. The cost must be beyond the control of the Company's management and is not a risk in respect of which a prudent utility would take risk mitigation steps;

[3] Refer to Mercer's Report "Estimated 2012 Funding Costs – EGD Pension Plans", filed as Appendix B.

iii. The cost increase/decrease must not otherwise be reflected in the per customer revenue cap;

iv. Any cost increase must be prudently incurred; and

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

16. Each of the above-noted criteria is evaluated below with reference to the issue of pension plan funding:

i. The event must be causally related to an increase / decrease in cost:

17. As described earlier in this evidence, market volatility and a growing pension obligation due to employee services rendered is expected to take the RPP and SERP from a surplus to a deficit position. The expected deficit will trigger contribution requirements as mandated by the PBAO.

18. Given the flow-through basis of pension cost recognition, any required contribution will result in an increased cost to EGD.

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

19. EGD manages and incurs pension costs as calculated by Mercer and as stipulated and governed by the PBAO and FSCO. Due to a new PBAO regulation introduced on June 23, 2009 EGD must file an annual cost certificate to prove the plan is in a

surplus to maintain its contribution holiday. The current estimate of this filing[4] indicates a deficit triggering the need for 2012 contributions. Had it not been for the change in regulation, the contribution holiday would have continued until the next filing. The change in regulation is clearly beyond the control of management and the costs being incurred are those that would be incurred a prudent utility to remain compliant with the PBAO and FSCO.

20. Further EGD manages its pension plan over the long term as set out in its Statement of Investment Policies and Procedures. For this reason annual pension costs are not subject to management discretion. The market volatility over the past several years was broad-based and it impacted virtually all segments of the economy. These market conditions were beyond the control of management and given the long term management of the plan could not have been reasonably mitigated by EGD's management without compromising the long term objectives of the plan. Therefore the need for funding in 2012 is a result of current market conditions and not from any aspect of management of the plans within the control of EGD.

iii. The cost increase/decrease must not otherwise be reflected in the per customer revenue cap:

21. Since the plan was in a surplus position in recent years (thus precluding the Company from making contributions), no amounts were included in the per customer revenue cap calculations in respect of the plan. Thus, this is an incremental cost not currently recovered in rates.

[4] Refer to Mercer's Report "Estimated 2012 Funding Costs – EGD Pension Plans", filed as Appendix B.

iv. Any cost increase must be prudently incurred:

22. EGD's estimated 2012 contribution requirement of $17.7 million arises from the changes to the PBAO and primarily includes employee service cost related contributions. The estimated contribution amount is based Mercer's best estimate as of August 31, 2011 and must be made to remain compliant with the PBAO, thereby satisfying the prudence criteria. The strong past performance of the plan, which led to the accumulation of a significant funding surplus prior to the downturn in financial markets (as noted in Appendix A) further establishes the Company's prudence in management of the plan.

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

23. The anticipated cost increase for 2012 is expected to be $17.7 million, significantly higher than the threshold of $1.5 million.

<u>Proposed mechanics of the requested cost recovery</u>

24. As noted above, the Company's projected pension funding liability meets the Z factor criteria. The exact 2012 pension cost will be determined based on the actuarial valuation of the RPP and SERP conducted as at December 31, 2011, which will become available early 2012.

25. EGD proposes that the estimated pension cost of $17.7 million be included in the revenue requirement as a Z factor item in this application. Further, given the timing and the potential variability associated with the year-end valuation and the

inconclusive information known at this time, EGD proposes that the Z factor for pension costs should be coupled with a pension cost variance account.

26. Once the valuation at December 31, 2011 becomes available and the contribution requirement in 2012 (i.e. pension cost) becomes known, any variance from the estimated cost of $17.7 million will be transferred to this variance account for future refund to or collection from ratepayers. This process will ensure that the net recovery in rates is fully aligned with the costs ultimately incurred by EGD.

Summary

27. EGD is faced with increased pension costs as a result of external events that:
- Were entirely beyond the control of EGD management;
- Were unexpected in nature;
- Did not form part of base rates in the current IR term; and
- Will likely lead to a contribution requirement that will increase costs for EGD.

28. EGD management:
- Has demonstrated prudence in its approach to managing these costs;
- Has established that the criteria for a Z-factor have been met; and
- Continues to proactively manage the plan and FSCO filing requirements in a cost effective manner while ensuring compliance with pension legislation, and accounting guidelines.

29. In light of the above, the Company respectfully requests Board approval for inclusion of $17.7 million in pension costs as a Z factor in its revenue requirement for 2012. In addition, the Company requests that the Board approve the establishment of a pension cost variance account.

Witnesses: S. Kancharla
R. Lei
A. Patel

EGD – REGISTERED PENSION PLAN (“RPP”)

($ millions)

Going Concern Basis[1]	2011[2]	2010	2009	2008[3]	2007	2006	2005	2004
Assets	712.3	736.2	698.7	634.7	802.3	821.2	767.3	706.3
Liabilities	709.4	685.7	641.5	637.1	615.6	614.4	576.6	529.7
Funding Excess/(Surplus)	2.9	50.5	57.2	(2.4)	186.7	206.8	190.7	176.6

Solvency Basis[4]								
Assets	711.7	733.8	698.1	635.2	801.7	820.6	766.7	705.7
Liabilities	789.4	702.0	666.1	611.7	664.8	640.9	631	562
Funding Excess/(Surplus)	(77.7)	31.8	32.0	23.5	136.9	179.7	135.7	143.7

[1] Calculated assuming the plan will be in existence long term.
[2] Per Mercer’s Report “Estimated 2012 Funding Costs – EGD Pension Plans”, filed as Appendix B to this Exhibit.
[3] Although 2008 shows a deficit, funding was not required as the last filing in 2006 showed a plan surplus. The filing of an annual cost certificate was only required after June 23, 2009.
[4] Calculated on a short term basis (i.e the plan will be wound up).

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CONSULTING. OUTSOURCING. INVESTMENTS.

ESTIMATED 2012 FUNDING COSTS - EGD PENSION PLANS

ENBRIDGE GAS DISTRIBUTION INC.

29 SEPTEMBER 2011

MARSH & McLENNAN COMPANIES

Note to reader regarding actuarial valuations and projections:

This report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A projection is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future.

If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the projection date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from the projection date to the valuation date, and from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The projection results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the projection.

Should the plan be wound up, the going-concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound-up on the valuation date. Emerging experience will affect the wind-up financial position of the Plan assuming it is wound-up in the future. In fact, even if the plan were wound-up on the projection date, the financial position would continue to fluctuate until the benefits are fully settled.

Because actual plan experience will differ from the assumptions used in this projection, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a projection or a valuation report.

CONTENTS

1

Introduction

Purpose

At the request of Enbridge Gas Distribution Inc. (the "Company"), we have estimated the projected December 31, 2011 financial position and 2012 minimum funding requirements for the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "EGD RPP" or the "Plan") based on economic conditions at August 31, 2011. Actual results as at December 31, 2011 will differ from this projection based on the economic environment as at December 31, 2011. We understand this report will be provided to the Ontario Energy Board (the "OEB") in conjunction with Enbridge Gas Distribution Inc.'s application for recovery of 2012 pension costs from ratepayers.

The information presented is prepared for the internal use of the Company and for filing with the OEB. This information presented is not intended or suitable for any other purpose.

2

Background Information

Determination of Contribution Requirements

The EGD RPP consists of a defined benefit ("DB") provision and a defined contribution ("DC") provision. Minimum required contributions to the DB component are determined based on actuarial valuations filed with the Financial Services Commission of Ontario ("FSCO") and the Canada Revenue Agency ("CRA"). Valuations may be filed at the plan sponsor's discretion, but must be filed at least once every three years. Contributions in between filings are fixed (with the below noted exception).

EGD filed an actuarial valuation as at December 31, 2009. Accordingly, the next valuation must be filed no later than December 31, 2012.

We have also conducted an actuarial valuation for management information purposes as at December 31, 2010 that was not filed with FSCO or CRA. This valuation is the basis for the projections contained herein.

Regulatory Changes

Regulation 239 / 09 to the *Pension Benefits Act (Ontario)* was filed on June 23, 2009 and included a number of changes to the Regulations. In particular, for fiscal years 2009 to 2012 (inclusive), plan sponsors taking contribution holidays are required to file a Cost Certificate with FSCO within 90 days of the start of the fiscal year as evidence that sufficient surplus[1] remains to justify the contribution holiday.

If a contribution holiday cannot be justified, then contributions must resume in accordance with the most recently filed valuation with FSCO and CRA.

[1] On both a going-concern and solvency basis.

Historical Funding

Due to historical plan surplus in the DB component, DB cash contributions have not been required for over 10 years. In addition, the DB surplus has been used to cover contributions to the DC component. Historical costs to the DB and DC component are summarized below.

	DB Service Cost	DC Service Cost	Total Plan Service Cost	Total Plan Contribution
2002	$8.5M	$0.5M	$9.0M	$0
2003	$8.6M	$0.7M	$9.3M	$0
2004	$8.9M	$0.8M	$9.7M	$0
2005	$9.9M	$0.8M	$10.7M	$0
2006	$12.1M	$1.1M	$13.2M	$0
2007	$14.4M	$1.3M	$15.7M	$0
2008	$15.7M	$1.4M	$17.1M	$0
2009	$14.8M	$1.4M	$16.2M	$0
2010	$14.7M	$1.4M	$16.1M	$0
2011	$16.3M	$1.4M	$17.7M	$0
Total	**$123.9M**	**$10.8M**	**$134.7M**	**$0**

Current Economic Environment

The financial markets have not been favourable to pension plans in Canada in 2011. In particular, the health of pension plans has deteriorated due to the following events:

- Solvency discount rates have dropped by approximately 0.80% from the beginning of the year to August 31, 2011.[2] A reduction in discount rates leads to an increase in liabilities.
- Equity markets have been slightly negative through August 31, 2011.

For the average Canadian pension plan, these factors have resulted in a decrease in solvency and transfer ratios of over 10% as at August 31, 2011.

[2] Solvency discount rates are based on the yields on long-term Government of Canada bonds, plus a prescribed spread set by the Canadian Institute of Actuaries. To August 31, 2011, long-term bond yields have decreased 0.50%, and the prescribed spread had dropped by 0.30%.

Implications for EGD

If not for the regulation changes noted above, the contribution holiday could have been maintained through 2012 until the next valuation falls due regardless of interim plan experience. Even with the regulation changes, the contribution holiday was expected to continue for three to five years following the December 31, 2009 valuation if plan experience was as expected. However, poor experience as noted above has caused the financial health of the plan to deteriorate more than expected. Accordingly, contributions will likely be required in 2012.

3

Financial Results

Estimated Financial Position at December 31, 2011

We have projected the results of the December 31, 2010 actuarial valuation of the EGD RPP to December 31, 2011 for the purpose of estimating the Plan's financial position and determining whether or not the current contribution holiday can be maintained in 2012. **The projection is based on the economic environment as at August 31, 2011 and assumptions described in Appendix C. The actual economic environment as at December 31, 2011 and actual plan experience between August 31, 2011 and December 31, 2011 may differ significantly from these assumptions.**

For simplicity, we have only included the assets and liabilities with respect to the DB provision of the EGD RPP in the balance sheets shown below.

Projected Going-Concern Balance Sheet at December 31, 2011

The table below details the going-concern financial position of the EGD RPP as at December 31, 2010, as well as the projected position as at December 31, 2011.

Going-Concern Financial Position ($Millions)	12.31.2010 (Actual)	12.31.2011 (Projected)
Assets	$736.2	$712.3
Liabilities	$685.7	$709.4
Funding excess (shortfall)	$50.5	$2.9
Funded ratio	107%	100%

Projected Solvency Balance Sheet at December 31, 2011

The table below details the solvency financial position of the EGD RPP as at December 31, 2010, as well as the projected position as at December 31, 2011.

Solvency Financial Position ($Millions)	12.31.2010 (Actual)	12.31.2011 (Projected)
Assets	$735.6	$711.7
Liabilities	$702.0	$789.4
Solvency excess (deficiency)	$33.6	($77.7)
Solvency ratio	105%	90%

Summary of Minimum Required Contributions – EGD RPP

Based on the projected solvency position at December 31, 2011, the EGD RPP is not expected to have sufficient surplus to maintain the current contribution holiday in 2012 under the circumstances postulated in this report. Therefore, in accordance with Regulation 239/09 minimum contributions to the DB component are expected to revert back to the current service cost contribution rates determined in the December 31, 2009 valuation. DC contributions will also be required.

Special payments to amortize the solvency deficiency will not be required if a valuation is not filed as at December 31, 2011.

Estimated Cash Contributions – Valuation Not Filed ($Millions)	2012
DB current service cost (projected)	$15.6
Special payments (projected)	n/a
Total DB contributions (projected)	$15.6
DC current service cost (projected)	$1.5
Total DB and DC contributions (projected)	**$17.1**

If Enbridge were to file a valuation of the EGD RPP as at December 31, 2011, the current service cost would be recalculated based on current market assumptions and special payments to amortize the solvency deficiency would also be required. In this scenario, 2012 contribution requirements are estimated to be as follows:

Estimated Cash Contributions – Valuation Filed ($Millions)	2012
DB current service cost (projected)	$17.0
Special payments (projected)	$17.4
Total DB contributions (projected)	$34.4
DC current service cost (projected)	$1.5
Total DB and DC contributions (projected)	**$35.9**

For greater clarity, the contributions required if a valuation is filed reflect the true cost of the plan in the current economic environment, even though legislation permits lesser funding if a valuation is not filed.

Summary of Minimum Required Contributions – SERP/SSERP

Enbridge also sponsors two supplementary pension arrangements:

- The Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates (the "SERP"); and
- The Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. (the "SSERP").

We estimate cash contributions of approximately $0.6M will be required for the SERP in 2012. No contribution requirements are anticipated in respect of the SSERP.

Important to Note

The purpose of this report is to estimate the December 31, 2011 financial position and 2012 minimum required contributions. However, the occurrence and/or level of required contributions in 2012 is highly dependent on:

- Equity market returns between August 31, 2011 and December 31, 2011;
- Changes in long-term government bond yields between August 31, 2011 and December 31, 2011;
- Changes the prescribed spread used to determine solvency discount rates; and
- Demographic experience (only revealed if Enbridge chooses to file an actuarial valuation as at December 31, 2011).

These items will cause actual results as at December 31, 2011 to differ from the estimate provided in this report.

For illustrative purposes, we estimate that it would take one of the following events (or a combination thereof) in order for the financial position of the EGD RPP to improve enough to maintain the contribution holiday for 2012:

1. The pension fund returns 16% (net of expenses) between September 1, 2011 and December 31, 2011.
2. Discount rates increase by 1.0% (either from changes in long-term government bond yields or the prescribed spread used in calculating solvency discount rates) between September 1, 2011 and December 31, 2011.

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Actuarial Opinion

In our opinion, for the purposes of the projection,

- The membership data on which the valuation is based are sufficient and reliable;
- The assumptions are appropriate; and
- The methods employed in the valuation are appropriate.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the *Pension Benefits Act (Ontario)*.

Chris Heller
FCIA, FSA

September 29, 2011
Date

Allen Hornung
FCIA, FSA

September 29, 2011
Date

APPENDIX A

Required Disclosures

Terms of Engagement

In accordance with our terms of engagement with the Company, our projections are based on the following material terms:

- They have been prepared in accordance with applicable pension legislation and based on methods and actuarial assumptions that are consistent with actuarial standards of practice in Canada;

- We have reflected a margin for adverse deviations in our going concern projection by reducing the going-concern discount rate by 0.59% per year; and

- We have reflected the Company's decisions for determining the solvency funding requirements, summarized as follows:

  - The same plan wind-up scenario was hypothesized for both hypothetical wind-up and solvency valuations;

  - Certain excludable benefits were excluded from the solvency liabilities; and

  - The solvency financial position was determined on a projected market value basis.

- We have projected assets forward using benchmark asset returns (net of expenses) to August 31, 2011 and our best estimate of asset returns (net of expenses) for the remainder of 2011. Projected cash flows over 2011 have also been incorporated.

- We have projected liabilities forward using the expected cost of benefits accruing over 2011, reflecting interest over 2011 and adjusting year-end assumptions based on the economic environment as at August 31, 2011. Projected cash flows over 2011 have also been incorporated.

Our calculations are based on the assumptions and methodology described in Appendix C. We have used the same going-concern valuation assumptions and methods as were used for the valuation as at December 31, 2010.

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions as at August 31, 2011. Emerging experience will affect the funded position of the Plan.

Our calculations are based on an extrapolation of a valuation performed using membership data as at December 31, 2010. The membership data used in our calculations is summarized in Appendix D.

Our calculations reflect the provisions of the Plan as at August 31, 2011. Based on the information provided by the Company, no substantive amendments have been made to the Plan since that date. A summary of the plan provisions is provided in Appendix E.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent August 31, 2011 which, in our opinion, would have a material impact on the results of the projection.

Next Required Valuation

In accordance with pension benefits legislation, the next actuarial valuation of the Plan to be filed with FSCO and CRA will be required as at a date not later than December 31, 2012, or as at the date of an earlier amendment to the Plan. Unless a new cost certificate is filed as of January 1, 2012 demonstrating that the Plan has sufficient surplus, employer current service cost contributions must resume in 2012.

Gain and Loss Analysis

A reconciliation of the actual going-concern financial position between December 31, 2010 and the projected going-concern financial position at December 31, 2011 follows:

Reconciliation of financial status ($millions)	2011
Funding excess (shortfall) as at December 31, 2010	$50.4
Interest on funding excess (funding shortfall) at 5.75% per year	$2.9
DB contributions drawn from funding excess, with interest	($16.3)
DC contributions drawn from funding excess, with interest	($1.4)
Net investment return different than expected	($32.7)
Funding excess (shortfall) as at current valuation	$2.9

Solvency Incremental Cost

The solvency incremental cost is an estimate of the present value of the projected change in the solvency liabilities from December 31, 2010 to December 31, 2011 (before assumption changes), adjusted for benefit payments expected to be made over the period.

The estimated 2011 solvency incremental cost determined in this projection is $24.8M.

Discount Rate Sensitivity

The following table summarises the effect on the liabilities and current service costs shown in this report of using a discount rate which is 1.00% lower than that used in the projection:

Scenario	Projection Basis	Reduce Discount Rate by 1%
Going-concern liabilities	$709.4	$811.6
Solvency liabilities	$789.4	$920.7
DB current service cost	$17.0	$21.0

Projected Hypothetical Wind-up Balance Sheet at December 31, 2011

The table below details the hypothetical wind-up financial position of the EGD RPP as at December 31, 2010, as well as the projected position as at December 31, 2011.

Solvency Financial Position ($Millions)	12.31.2010 (Actual)	12.31.2011 (Projected)
Assets	$735.6	$711.7
Liabilities	$828.5	$931.6
Wind-up excess (deficiency)	($92.9)	($219.9)

The assumptions and methodology used to determine the projected hypothetical wind-up balance sheet as at December 31, 2011 are described in Appendix C.

APPENDIX B

Plan Assets

The DB assets of the Plan are held in trust by CIBC Mellon. We have relied upon the audited fund statements provided by PriceWaterhouseCoopers LLP as at December 31, 2010.

The starting point for our projection of assets was the market value of assets as at December 31, 2010 of $736.2M.

Investment Policy

The plan administrator adopted a statement of investment policy and procedures, last revised in 2011. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The target asset mix as at August 31, 2011 is provided for information purposes:

	Investment Policy Target
Canadian equities	21.0%
Global equities	17.0%
Emerging market equities	6.5%
Fixed income – universe	30.0%
Fixed income – real return	10.0%
Infrastructure	9.0%
Real estate	6.5%
Cash and cash equivalents	0.0%
	100%

Because of the mismatch between the Plans' assets (which are invested in accordance with the above investment policy) and the Plans' liabilities (which tend to behave like long bonds) the Plan's financial position will fluctuate over time. These fluctuations could be significant and could cause the Plan to become under, or over, funded even if the Company contributes to the Plan based on the funding requirements presented in this report.

APPENDIX C

Actuarial Methods and Assumptions

Actuarial Methods – Projected Going-concern Basis at December 31, 2011

Valuation of Assets

For purposes of this estimate, we have projected the market value of assets at December 31, 2010 using benchmark asset returns (net of all expenses) of -0.68% from January 1, 2011 to August 31, 2011, and our best estimate of asset returns (net of all expenses) of 1.95% from September 1, 2011 to December 31, 2011. Therefore, the annual rate of return over 2011 (net of all expenses) assumed in our projection is 1.27%.

Projected cash flows over 2011 have been incorporated into our projection.

Actual assets as at December 31, 2011 will differ from this estimate.

Valuation of Actuarial Liabilities and Current Service Cost

For purposes of this projection, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings.

Actuarial Assumptions – Projected Going-Concern Basis at December 31, 2011

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

For purposes of this projection, we have used the same going-concern valuation assumptions as were used for the December 31, 2010 valuation, summarized on the following page.

Assumption	Current Valuation
Discount rate:	5.75%
Inflation:	2.25%
ITA limit / YMPE Increases:	2.75%
Pensionable Earnings Increases:	4.00%
Post retirement Pension Increases:	1.125%
Retirement Rates:	Age related table
Termination Rates:	Age related table
Mortality Rates:	100% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality Improvements:	Fully generational using Scale AA
Disability Rates:	None
Eligible Spouse at Retirement:	80%
Spousal Age Difference:	Male two years older
DB/DC Choice:	Continue in current component
Benefits Subject to Consent:	Consent on early retirement

The assumptions are best-estimate with the exception that the discount rate includes a margin for adverse deviations, as shown below.

Our assumptions are based on the economic environment as of August 31, 2011 and input provided by the Company for the December 31, 2010 valuation. Actual assumptions as at December 31, 2011 will reflect the economic environment and input from the Company at that time, and may differ from those used in this projection.

Sample rates from the age related tables are summarized below:

Age	Termination - Male	Termination - Female	Retirement
20	5.0%	9.5%	0.0%
25	5.0%	13.0%	0.0%
30	5.0%	11.0%	0.0%
35	4.6%	8.5%	0.0%
40	3.0%	4.0%	0.0%
45	2.5%	3.9%	0.0%
50	1.5%	2.8%	0.0%
55	0.0%	0.0%	5.0%
56	0.0%	0.0%	5.0%
57	0.0%	0.0%	7.5%
58	0.0%	0.0%	7.5%
59	0.0%	0.0%	10.0%
60	0.0%	0.0%	20.0%
61	0.0%	0.0%	20.0%
62	0.0%	0.0%	20.0%
63	0.0%	0.0%	20.0%
64	0.0%	0.0%	20.0%
65	0.0%	0.0%	100.0%

A 20% retirement rate is assumed in lieu of the above rate in the year in which a member qualifies for early retirement with an unreduced pension and in each subsequent year until age 65.

For members who terminate from the Plan before being eligible to retire we have assumed two-thirds will elect a commuted value determined on a basis consistent with the 2009 CIA Standard, and that one-third will elect a deferred, with pension commencement at age 55.

The following is a summary of the rationale for the material assumptions that are expected to be used as at December 31, 2011.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy.
- Additional returns assumed to be achievable due to active equity management equal to the fees related to active equity management. Such fees were determined by the difference between the provision for total investment expenses and the hypothetical fees that would be incurred for passive management of all assets.
- Implicit provision for investment and non-investment administrative expenses determined as the expected rate of investment and administrative expenses to be paid from the fund in the future. While recent experience has differed from the assumption, our discussions with management have led us to conclude that this assumption is appropriate.
- A margin for adverse deviations of 0.59%.

The discount rate was developed as follows:

Assumed investment return	6.73%
Additional returns for active management	0.11%
Investment management and administrative expense provision	(0.50%)
Margin for adverse deviation	(0.59%)
Net discount rate	5.75%

Inflation

The inflation assumption is based on the mid-point of the Bank of Canada's inflation target range of between 1% and 3%, and market expectations of long-term inflation implied by the yields on nominal and real return bonds at the valuation date of 2.5%.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

This assumption is based on Company expectations.

Actuarial Methods and Assumptions – Projected Solvency and Wind-up Basis at December 31, 2011

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound-up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit. For the purposes of the hypothetical wind-up valuation, the Plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, including benefits that would be immediately payable if the employer's business were discontinued on the valuation date, with all members fully vested in their accrued benefits.

The circumstances in which the Plan wind-up is assumed to have taken place are as follows:

- Membership in the Plan ceases on the valuation date; and
- No projection of salaries and YMPE are assumed to occur after the valuation date for active and suspended members.

Thereby giving rise to the following benefits:

- Active and suspended members not within 10 years of pensionable age (under the age of 55) receive the termination benefit under the Plan;
- Active and suspended members within 10 years of pensionable age (age 55 and older) receive the retirement benefit under the Plan; and
- Deferred pensioners, pensioners and survivors receive the benefit to which they are entitled on the valuation date.

It is assumed that, on Plan wind-up, the Company would grant consent to early retirement for all active members age 55 and over.

No benefits payable on Plan wind-up were excluded from our calculations.

Upon Plan wind-up members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for August 31, 2011.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities. However, there is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. Therefore, we have relied upon the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2010 and December 30, 2011*, reflecting additional supplemental information to August 2011.

In determining the financial position of the Plan on the solvency basis, we have valued those benefits that would have been paid had the Plan been wound-up on the valuation date, with the exception of certain benefits which may be excluded, as permitted by the Act. Specifically, future cost-of-living increases on pensions in payment were excluded from our calculation of solvency liabilities. All members are assumed to be fully vested in their accrued benefits.

We have not included a margin for adverse deviation in the solvency and hypothetical wind-up valuations.

The assumptions below are based on economic conditions as at August 31, 2011.

Basis for Benefits Assumed to be Settled Through a Lump Sum	
Non-indexed interest rate:	3.40% per year for 10 years, 4.70% per year thereafter
Partially-indexed (50%) interest rate:	2.40% per year for 10 years, 3.30% per year thereafter
Partially-indexed (55%) interest rate:	2.30% per year for 10 years, 3.10% per year thereafter
Basis for Benefits Assumed to be Settled Through the Purchase of an Annuity	
Non-indexed interest rate:	3.70% per year
Partially-indexed (50%) interest rate:	2.29% per year
Partially-indexed (55%) interest rate:	2.11% per year
Termination expenses:	$600,000

Termination Expenses

To determine the hypothetical wind-up and solvency position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested. Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the solvency liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected solvency liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going-concern assumptions as follows:

- Pensionable earnings, the *Income Tax Act* pension limit and the Year's Maximum Pensionable Earnings increase in accordance with the related going-concern assumptions;
- Active members accrue pensionable service in accordance with the terms of the Plan; and
- Cost of living adjustments are consistent with the inflation assumption used for the going-concern valuation.

APPENDIX D

Membership Data

Analysis of Membership Data at December 31, 2010

For purposes of this estimate, we have based our projection on membership data as at December 31, 2010, which was provided by Enbridge. Membership data was projected forward based on the assumptions described in Appendix C.

Plan membership data as at December 31, 2010 are summarized below.

	12.31.2010
Active and Disabled Members Accruing Defined Benefit Service (Non-SMEs)	
Number	1,742
Total base earnings at the valuation date	$128,113,000
Average base earnings at the valuation date	$73,500
Average years of Non-SME DB pensionable service	13.3 years
Average age	46.0 years
Active and Disabled Members Accruing Defined Benefit Service (SMEs)	
Number	31
Total base earnings at the valuation date	$6,189,000
Average base earnings at the valuation date	$199,600
Average years of Non-SME DB pensionable service	12.3 years
Average years of SME DB pensionable service	2.8 years
Average age	50.0 years
Suspended Defined Benefit Members Accruing Defined Contribution Service	
Number	85
Total base earnings at the valuation date	$7,226,000
Average base earnings at the valuation date	$85,000
Average years of Non-SME DB pensionable service	5.4 years
Average age	45.0 years
Other Suspended Defined Benefit Members (Non-SMEs)	
Number	13
Total base earnings at the valuation date	$1,263,000
Average base earnings at the valuation date	$97,200
Average years of Non-SME DB pensionable service	4.7 years
Average age	39.0 years
Other Suspended Defined Benefit Members (SMEs)	
Number	15
Total base earnings at the valuation date	$3,596,000
Average base earnings at the valuation date	$239,700
Average years of Non-SME DB pensionable service	8.9 years
Average years of SME DB pensionable service	1.5 years
Average age	48.5 years

	12.31.2010
Active Defined Contribution Members without Defined Benefit Service	
Number	202
Total base earnings at the valuation date	$16,115,000
Average base earnings at the valuation date	$79,800
Average age	40.5 years
Suspended Defined Contribution Members without Defined Benefit Service	
Number	9
Total base earnings at the valuation date	$1,121,000
Average base earnings at the valuation date	$124,600
Average age	38.1 years
Deferred Pensioners	
Number	192
Total annual pension*	$935,000
Average annual pension*	$4,900
Average age	48.9 years
Pensioners and Survivors	
Number	1,432
Total annual lifetime pension	$28,339,700
Average annual lifetime pension	$19,800
Total annual temporary pension	$2,088,000
Average annual temporary pension	$6,900
Average age	71.7 years

APPENDIX E

Summary of Plan Provisions

For purposes of this projection, we have reflected the plan provisions in effect on August 31, 2011. Since December 31, 2010, the Plan has been amended to allow immediate vesting, and to reflect various housekeeping items.

DB Component

The following is a summary of the main provisions of the DB component of the Plan in effect on August 31, 2011. This summary is not intended as a complete description of the Plan.

Background	The Plan became effective January 1, 1971. Benefits are based on a set formula and are entirely paid for by Enbridge. Effective July 1, 2001, the Plan was redesigned for all active or suspended members at that date. Prior to the redesign, participants in the DB component of the Plan accrued Contributory credited service. Following the redesign, all active and suspended members were required to elect to participate in either the DB component or the DC component of the Plan for future service. Participants in the DB component of the Plan accrue non-contributory or SME credited service. In the future, members who are not SMEs may switch between the DB and DC components on the January 1 following the date they achieve 40 points or 60 points. Any changes will affect service after the decision point only. Members who are SMEs must participate in the DB component of the Plan.
Eligibility for Membership	New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component.
Vesting	All employees are immediately vested as of July 1, 2011.
Employee Contributions	No employee contributions are required or permitted based on the current plan provisions. Prior to July 1, 2001, employee contributions were required.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date • A member becomes immediately vested and may choose to retire as early as age 55.

Normal Retirement Pension	**Contributory Service:** 2.0% of Final Five Year Average Earnings multiplied by years of contributory credited service; less 100% of the Contributory Canada Pension Plan Entitlement. **Non-Contributory Service:** 1.2% of Final Three Year Average Earnings multiplied by years of non-contributory credited service; less 50% of the Non-Contributory Canada Pension Plan Entitlement; **SME Credited Service:** 2.0% of Final Three Year Average Earnings multiplied by years of SME credited service.
Final Five Year Average Earnings	Final Five Year Average Earnings is calculated using the highest 60 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, including 50% of the actual bonus received for senior executive employees.
Final Three Year Average Earnings	Final Three Year Average Earnings is calculated using the highest 36 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, plus the sum of the highest three Pensionable Bonus payments made in the last five years divided by 3.
Canada Pension Plan Entitlement	**Contributory Service:** One thirty-fifth of 25% of the lesser of the average earnings in the 60 months immediately preceding the date of exit and average of the YMPE in the five calendar years, including the current year, preceding the date of exit, multiplied by contributory credited service, to a maximum of 35 years. **Non-Contributory Service:** Calculated as if the member had reached age 65, multiplied by the ratio of the member's non-contributory credited service after the later of January 1, 1966 or age 18, to the number of years of possible CPP coverage to age 65, recognizing the permitted dropout period of 15%, and reduced by 6% per year for every year the retirement date precedes age 65, to a maximum reduction of 30%.

Early Retirement Pension	The following benefits apply if a member retires early with the Company's consent: • If the member has attained age 60, the pension payable is as described above in the Normal Retirement section. • If the member has 30 years of continuous Service or has attained age 60, the member is eligible for the benefits described in the previous paragraph plus, for contributory credited service, an additional benefit of a bridge pension payable to age 65 equal to 100% of the Contributory Canada Pension Plan Entitlement. • If the member has not attained age 60 the member is also eligible, for non-contributory credited service, for an additional benefit of a bridge pension payable to age 60 equal to 50% of the Non-Contributory Canada Pension Plan Entitlement. • If the member has not attained age 60 or 30 years of continuous service at retirement, an early retirement reduction of 5% per year is applicable from age 60 in respect of contributory and non-contributory credited service. For SMEs, the early retirement reduction is 3% per year for SME credited service. The reduction applies to the benefit described in the immediately preceding paragraphs including the bridge pensions. If a member retires without company consent the benefit is actuarially equivalent to the benefit payable at age 65.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of: • 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and • $2,552.22, or such other maximum as may apply from time to time indexed to the date of pension commencement, multiplied by his total credited Service and reduced for early retirement in accordance with the *Income Tax Act* rules.
Indexation of Pensions in Payment	On December 1 of each year a contractual cost of living increase equal to a percentage of the annual increase in the Consumer Price Index will apply to pensions in payment for at least one year. This percentage is 55% for contributory credited service and 50% for non-contributory and SME credited service. Indexation only applies to members that retire from active membership. Prior to July 1, 2001, any increases to pensions in payment were on an ad-hoc basis.

Death Benefits	**Death Before Eligible for Early Retirement** If a member dies before he is eligible for early retirement benefits, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to 100% of the commuted value of the member's reduced accrued pension deferred to age 55, in respect of all credited service. **Death After Eligibility for Early Retirement** If a member dies after his early retirement date and before his pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive either a lump sum settlement or an immediate pension equal in value to 100% of the commuted value of the member's reduced accrued pension, in respect of all credited service. **Death After Retirement** The death benefit payable is in accordance with the form elected. The normal form of pension is a Joint and 60% Survivor annuity for members with a spouse and a life annuity with a 15-year guarantee period for single members.
Termination Benefits	If a member's employment terminates for reasons other than death or retirement, the member is entitled to their reduced accrued pension deferred to age 55. The Member has the option to transfer the value of the benefit to a locked-in RRSP.
Disability Benefits	Disabled members are eligible to retire at age 65. For members whose disability commenced before July 1, 2001 salary is assumed to increase with the Average Industrial Wage, while for members whose disability commences after July 1, 2001 salary is assumed to increase with inflation, subject to a maximum of 5% per year, to retirement. The disabled member continues to accrue credited service while disabled.

DC Component

The following is a summary of the main provisions of the DC component of the Plan in effect on August 31, 2011. This summary is not intended as a complete description of the Plan.

Background	The DC component of the Plan became effective July 1, 2001. Employer contributions are remitted to individual member accounts and are credited with interest. Members receive the balance of their individual employer account upon termination, death or retirement.
Eligibility for Membership	New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component.
Vesting	All employees are immediately vested as of July 1, 2011.
Employee Contributions	No employee contributions are required or permitted.
Employer Contributions	Employer contributions to the DC component are based on a member's points. • less than 40 points: 4.0% of pensionable earnings[3] • 40 to 60 points: 5.5% of pensionable earnings • greater than 60 points: 7.0% of pensionable earnings
Maximum Contribution	The employer contributions are limited to the amounts under the ITA.
Pensionable Earnings	Base salary plus 50% of actual bonus received.

[3] For members who were participating in the DC component of the Plan at June 30, 2001, the minimum employer contribution is 5.0% of pensionable DC earnings.

MERCER

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Z FACTOR REQUEST RELATED TO CROSS BORES/SEWER LATERALS

Overview

1. On August 31, 2011, the Technical Standards and Safety Authority (the "TSSA") issued an Oil and Gas Pipeline Systems Code Adoption Document – Amendment FS-188-11 (the "TSSA Directive"). A copy of the TSSA Directive is attached as Appendix A, to this exhibit.

2. The TSSA Directive requires that each natural gas distributor incorporate into its pipeline system integrity procedures an "action plan" that will address cross bore issues (the "Action Plan"), including:
    a. A description of the steps to mitigate the potential of penetration of sewer lines by a natural gas pipeline during trenchless installation,
    b. A program that raises stakeholder awareness of the potential safety issues that could arise when attempting to clear a blocked sewer service line beyond the outside walls of a building, and
    c. An assessment of potential risks and a plan to mitigate these risks.

   The Action Plan must be available to TSSA for inspection by October 30, 2011.

3. In response to the TSSA Directive, Enbridge has prepared its Action Plan, subject to final revisions. A copy of the current version of the Action Plan is attached as Appendix B, to this exhibit. At a high level, Enbridge's Action Plan provides that Enbridge will undertake the following types of activities to address cross bore issues:
    a. New procedures for addressing blocked sewer lines,
    b. Public education/awareness and response campaign,
    c. New construction procedures when trenchless technologies are to be utilized,
    d. Legacy investigations (to seek to identify existing cross bores), and

e. Records management, research and development (to develop better installation records and safer construction and locate procedures).

4. All of the activities contemplated by Enbridge's Action Plan are new since 2007, when base rates for the current IRM term were set.

5. Enbridge forecasts that the costs of implementing its Action Plan in 2012 will be approximately $5.8 million, comprised of $3.7 million of Operations & Maintenance ("O&M") costs and $2.1 million of capital costs. Enbridge's forecast increase in 2012 revenue requirement associated with implementing the Action Plan is $3.8 million.

6. Enbridge seeks Board approval of a Z factor to recover the revenue requirement impact associated with the implementation of its TSSA-mandated Cross Bore Action Plan. As set out herein, this newly mandated requirement meets the specified evaluation criteria for Z factor treatment, as set out in Enbridge's IRM Settlement Agreement.

<u>Background</u>

7. A cross bore is an unintended intersection of an existing utility by a second utility that can occur during construction when trenchless technologies are utilized. Stated differently, it is where one utility pipe unintentionally damages another, compromising the integrity of either one or both utility facilities.

8. Generally speaking, the cross bores that involve Enbridge pipes are intersections where Enbridge's lines unintentionally pass through sewer lines, and thus this evidence focuses on Enbridge lines through sewer lateral lines.

9. The cross bores have resulted from the fact that Enbridge has used trenchless installation methods since approximately 1970. Trenchless technologies have been widely used across North America for more than 30 years to install underground utilities. These technologies are faster, create less traffic disruption, are cost effective, and result in less damage to property, roadways, and tree roots. In some cases, the mandatory use of trenchless technologies has been a condition of municipal permit approval for the installation of gas plant in some locations. Trenchless installations of gas lines and other utilities are used primarily in established neighbourhoods and urban areas where open trench work would be expensive and intrusive. There are numerous types of these technologies employed, including but not limited to directional drills, ploughs, and torpedoes or moles.

10. These construction methods have led to operational efficiencies and cost savings because they are so much less disruptive than digging and re-filling trenches. However, from time to time the use of trenchless installation has inadvertently led to cross bores because municipalities typically do not have records of the location of sewer laterals, and the sewer laterals are difficult to locate with traditional equipment because they are made of non-conductive materials and were not installed with tracer wires.

11. Typically, the municipality owns the sewer lateral up to the property line and the property owner owns the remaining portion to the building. Most property owners will not know where their portion of the sewer lateral is buried, or have the expertise to locate it. Sewer trunk and lateral lines are generally installed deeper than natural gas lines, to avoid freeze-thaw issues. However, there may be some instances where the sewer laterals have been installed at shallower depths or gas lines have

been installed at deeper depths. This could result in natural gas lines inadvertently penetrating the sewer service lines during installation. Installation standards for sewer lateral lines vary considerably from area to area and over time according to many variables.

12. The potential danger from a natural gas line through a sewer lateral arises because those working on the sewer lateral may not know that a natural gas line is there. In many cases, the gas line can remain in the sewer lateral without creating an immediate problem; it may remain undetected for years. If the individual working on a sewer lateral blockage utilizes rotating auger or water jetting equipment to clear the blockage, and a natural gas cross bore is present, the natural gas line could be damaged. If the damage breaches the line, the natural gas will follow the path of least resistance. The natural gas could fill the sewer lateral and enter the building connected to the sewer lateral. If gas is not provided with a route that allows it to vent to the atmosphere, and if a source of ignition (such as a pilot light in a furnace or water heater) is present, an explosion and/or fire may occur.

13. The TSSA Directive is the culmination of a number of events that have transpired in the recent past and which have increased awareness in Ontario of the safety issues associated with cross bores.

14. In the past several years, there have been a number of tragic incidents in the United States related to cross bores and natural gas lines. One of these incidents involved Enbridge's affiliate St. Lawrence Gas ("SLG"), which experienced an incident which resulted in an explosion and fatality at a customer's home in Ogdensburg, New York. It was determined in that case that a gas line was inadvertently installed through the customer's sewer lateral several years earlier. Enbridge is aware of at least 20 other

incidents in the United States related to cross bores and natural gas lines, many of these occurring after the SLG incident.

15. In the past, it had generally been assumed that cross bores would not be a significant issue in Ontario, because sewer lines are generally installed below the frost line, which is lower than gas lines. Over the past number of years, it has become clear that this assumption is flawed. What has been determined is that, in some cases, sewer line installations are shallow because of site conditions or other factors. Enbridge has encountered and repaired approximately 44 sewer lateral cross bores in its franchise area since 2007.

16. These incidents, and the growing awareness of the potential dangers of cross bores, have led to a number of developments and initiatives.

17. The growing awareness of cross bore safety issues has led American pipeline safety authorities to develop and implement specific operational requirements for natural gas distribution utilities and has led some States to enact legislation requiring that sewer mains and services be located by the municipal sewer operator.

18. In addition, a number of organizations and associations in the United States and Canada have identified the issue and are addressing it through either standing or ad hoc committees. These include but are not limited to the North American Society of Trenchless Technology ("NASTT"), the Common Ground Alliance ("CGA"), the American Gas Association ("AGA"), the Cross Bore Safety Association ("CBSA"), the Distribution Contractors Association ("DCA") and the Canadian Gas Association ("CGA").

19. In late 2009 and throughout 2010, an Enbridge representative chaired a CGA Task Force on Cross Bore Safety whose mandate was to create a "white paper" on the cross bore issue to assist Canadian natural gas distribution utilities with best practices on risk assessment and mitigation strategies. The CGA Task Force on Cross Bore safety "white paper" was issued around September 2010.

20. Starting in 2009 and 2010, Enbridge began to create and implement a program to take proactive steps to address cross bore issues and reduce the chances of any serious incidents in its franchise area. To do this, Enbridge implemented new construction methods that are meant to minimize the risk of conflicts between sewer laterals and new gas line installations. Enbridge also implemented programs that aim to identify existing legacy cross bores, so that they can be rectified. To assist in that regard, Enbridge engaged the assistance of Dynamic Risk to develop a risk assessment model to determine the macro and micro factors that may assist with the determination of variables leading to locations of potential cross bore locations. Enbridge used this information in conjunction with basement elevation data obtained from the Municipal Property Assessment Corporation, sewer elevation data from municipal sources, where available, along with in-house knowledge to determine the potential magnitude of the cross bore risk.

21. Since that time, Enbridge has maintained and evolved its activities aimed at addressing cross bore issues, to prevent further cross bores and to identify existing cross bores and raise public awareness of the potential associated dangers.

<u>The TSSA Directive</u>

22. The cross bore issue was identified and discussed at the TSSA Risk Reduction Group on Pipelines meetings in March and June of 2011. Through those meetings,

it was determined that the TSSA wished to mandate and require gas utility initiatives to address cross bore issues. The TSSA Directive issued on August 31, 2011 (Appendix A to this exhibit) evidences the importance placed on the issue by the TSSA.

23. The TSSA Directive is an Oil and Gas Pipeline Systems Codes and Standards amendment document adopted under *The Technical Standards and Safety Act*, 2000, S.O. 2000, c. 16 and Ontario Regulation 223/01 and Ontario Regulation 210/01. Effectively, the TSSA Directive is an amendment to Ontario Regulation 210/01 and mandates that every natural gas distributor in Ontario must have an "action plan" to assess and mitigate the potential risks of gas line/sewer lateral cross bores completed and available to TSSA for inspection by October 30, 2011.

24. The TSSA Directive requires that the "Action Plan" must include:
    a. A description of the steps to mitigate the potential of penetration of sewer lines by a natural gas pipeline during trenchless installation,
    b. A program that raises stakeholder awareness of the potential safety issues that could arise when attempting to clear a blocked sewer service line beyond the outside walls of a building, and
    c. An assessment of potential risks and a plan to mitigate these risks.

Enbridge's Action Plan

25. In response to the TSSA Directive, Enbridge has created an "Action Plan" document, titled "Utility Cross Bores Action Plan for Compliance to CAD Amendment FS-188-11" to be presented to the TSSA for inspection. The Action Plan describes the nature of cross bore issues, and details how Enbridge will seek to avoid future cross bores and how Enbridge will raise public awareness and address legacy cross

bores. A copy of the current version of the Action Plan, which is essentially a final document (but subject to final revisions), is attached as Appendix B, to this exhibit.

26. Enbridge's Action Plan addresses the mandated items set out in the TSSA Directive, and is responsive to the matters described and recommended in the CGA "white paper" on cross bore issues.

27. The main elements of Enbridge's Action Plan (which are described in more detail in the Action Plan document) are the following:

a. *New procedures for addressing blocked sewer lines*

   The goal of these procedures is to have municipal sewer operators, plumbers, drain cleaners, homeowners and others who are clearing blocked sewer lines beyond the outside walls of a building using mechanical auger equipment or pressure water jetting equipment or other means call Ontario One Call to request a Natural Gas Sewer Safety Inspection prior to proceeding. This damage prevention initiative is similar to, and an expansion of, Enbridge's Call Before You Dig Program. Enbridge will respond and provide a Natural Gas Sewer Safety Inspection, which in most cases will confirm that there is no cross bore and it is safe to proceed (otherwise, Enbridge will take appropriate steps to remedy any conditions identified). Similar to Call Before You Dig, there will be no charge to customers/users of this service. This initiative is a response component of the stakeholder education/awareness campaign identified in part (b) of the TSSA Directive.

b. *Public education/awareness and response campaign*

   Enbridge has undertaken and will continue to undertake a number of activities to educate and alert municipalities, plumbers, drain cleaners, and property owners about the potential existence and danger of cross bores when clearing a blocked sewer lateral beyond the foundation of a building. This involves a number of activities. One of these activities is public meetings, where information and educational materials is provided to plumbers and municipal sewer operators. Enbridge has held these meetings throughout its franchise areas and may continue to do so, if appropriate. Enbridge continues to publicize the potential safety risk of cross bores through bill inserts, newspaper, and radio advertisements and other media channels to alert municipal sewer operators, plumbers, drain cleaners, and the general public to the danger of using power equipment to clear sewer lines beyond the foundation wall of buildings, if the sewer lines have not been checked for cross bores. These ongoing initiatives are required to address the stakeholder education/awareness component identified in part (b) of the TSSA Directive.

c. *New construction procedures when trenchless technologies are to be utilized*
Enbridge has now mandated new construction and excavation techniques for its installation work where trenchless technologies are to be utilized (section 20 of the Construction Manual). This involves site assessment and, where appropriate, the provision of private sewer lateral locates from a qualified service provider as part of the construction process. Enbridge's construction personnel (employees and contractors) have been trained about the potential risks of creating cross bores, and about the need to undertake detailed field reviews of installation areas to identify contributing factors showing a possible shallow sewer lateral. Enbridge's construction personnel have also been trained to always request Municipal sewer lateral locates and when to order private sewer lateral locates. When gas lines will be installed by trenchless technology and will be within 1 metre of the sewer lateral in any direction,

Enbridge's new construction procedures require that the bore path must be daylighted (exposed to light, so that it can be inspected). These procedures are required to address item (a) of the TSSA Directive (steps to mitigate the potential of penetration of sewer lines by a natural gas pipeline during trenchless installation).

d. *Legacy investigations (to seek to identify existing cross bores)*
In recognition of the fact that existing cross bores pose a safety risk, Enbridge has undertaken and plans to take future steps to investigate whether cross bores exist at locations that have been identified as having some risk. As previously noted, the locations that may be at highest risk of a cross bore are those where sewer laterals are shallow or natural gas lines are deeper than typical and where gas lines were installed using trenchless technologies. In the event that existing cross bores are discovered, they will be repaired. Also as previously noted, Enbridge engaged a risk management consultant and obtained pertinent information from Ontario's Municipal Property Assessment Corporation in conjunction with municipal sewer elevation data and in-house knowledge to attempt to establish a correlation between cross bores and site conditions in Enbridge's franchise area. Enbridge intends to investigate these properties over time, to search for and remedy cross bores, and to confirm whether such conditions actually correlate to an increased risk of cross bores. Enbridge is also participating in a cross bore safety task force project with the Operations Technology Development group of the Gas Technology Institute in Chicago, along with other North American gas distribution companies, to develop a risk assessment model based on data collected from actual cross bores in North America. The results of this study will be used to further enhance the search criteria for cross bores. These activities are required to

address item (c) of the TSSA Directive (an assessment of potential risks and a plan to mitigate these risks).

e. *Records management, research and development (to develop better installation records and safer construction and locate procedures)*
Enbridge will implement Information Technology ("IT") upgrades to allow it to better track the installation method of gas lines, and status of addresses that have been cleared of any cross bore. This information will allow Enbridge to streamline future calls. At present, Enbridge has been manually tracking sewer lateral information obtained. The system changes contemplated will be completed once the new Geographic Information System ("GIS") is fully operational and stable, which is expected to be the case in 2012. At the same time, information can be included about properties that are not at risk for cross bores because trenchless installation methods were not used. Enbridge will also continue to undertake research and development efforts to identify and create new and more cost-effective methods for locating sewer laterals and cross bores. These activities are required to address item (c) of the TSSA Directive (an assessment of potential risks and a plan to mitigate these risks).

28. As described above, each element of Enbridge's Action Plan is required to address the requirements of the TSSA Directive, particularly in respect of the TSSA requirement that each gas distributor develop a plan to "mitigate" the potential risks associated with cross bores.

29. The total forecast 2012 costs associated with the implementation of Enbridge's Action Plan are $5,772,825, as set out in the following chart, which is organized in the same categories as described above:

Components of Action Plan	Expenditure Type	Expenditure Amount
New procedures for addressing blocked sewer lines	Capital	$1,521
	O&M	$2,662,687
Public education/awareness and response campaign	Capital	0
	O&M	$300,000
New construction procedures when trenchless technologies are to be utilized	Capital	$1,844,697
	O&M	0
Legacy investigations (to seek to identify existing cross bores)	Capital	$16,000
	O&M	$668,920
Records management, research and development	Capital	$228,900
	O&M	$50,100
Totals	Capital	$2,091,118
	O&M	$3,681,707
		$5,772,825

Witnesses: C. Clark
L. Lawler

30. Details of these costs are set out in the following subparagraphs:

a. *New procedures for addressing blocked sewer lines*

Expenditure Description	Expenditure Type	Expenditure Cost	Work Volume
Ontario One Call Services Incremental call centre services to take calls and dispatch service provider	O&M	$13,687	5530
Emergency Natural Gas Sewer Safety Inspection Onsite inspections (within two hours) in response to calls from plumbers, homeowners and others who have a blocked sewer beyond the walls of a building.	O&M	$2,377,500	5530
Ontario One Call Services Incremental call centre services to take calls and dispatch service provider	Capital	$1,521	5530
Daylighting/Video Inspection excavate/inspect for possible cross bore where initial sewer safety inspection is inconclusive	O&M	$91,500	183
Claims and Repairs, repairs to sewer lines, gas lines and damaged property, where a cross bore is found	O&M	$180,000	15
Total Cost		$2,664,208	

Witnesses: C. Clark
L. Lawler

b. *Public education/awareness and response campaign*

Expenditure Description	Expenditure Type	Expenditure Cost
Education Materials all publicity materials/costs	O&M	$300,000
Total Cost		$300,000

c. *New construction procedures when trenchless technologies are to be utilized*

Expenditure Description	Expenditure Type	Expenditure Cost	Work Volume
Sewer Lateral Locate perform sewer lateral locates prior to construction	Capital	$1,757,967	7032
Daylight Witness Holes excavations required to determine that minimum clearances are maintained at sewer lateral crossing locations	Capital	$86,730	354
Total Cost		$1,844,697	

d. *Legacy investigations (to seek to identify existing cross bores)*

Expenditure Description	Expenditure Type	Expenditure Cost	Work Volume
Sewer Lateral Investigation perform video inspection of sewer laterals	O&M	$658,920	1734

Daylighting/video Inspections excavate or inspect areas of possible cross bores where sewer lateral investigations are inconclusive	O&M	$10,000	20
Relocations/Relay complete remedial work when a cross bore is found	Capital	$16,000	2
Total Cost		$684,920	

e. *Records management, research and development (to develop better installation records and safer construction and locate procedures)*

Expenditure Description	Expenditure Type	Expenditure Cost
IT System Change to record method used to install service line	Capital	$13,000
IT System Change to record method used to install gas main	Capital	$21,000
Sewer Lateral Clearance Tracking addition of resources to record sewer lateral clearance in GIS and investigate as-laid construction drawings for construction method	O&M	$50,100

Sewer Lateral Clearance Tracking addition of resources to record sewer lateral clearance in GIS and investigate as-laid construction drawings for construction method	Capital	$144,900
Research and Development of Sewer Lateral locating technologies research and develop safe and more cost-effective methods of locating sewer laterals	Capital	$50,000
Total Cost		$279,000

31. The Action Plan will be presented to representatives from the TSSA before the end of 2011. Based on the TSSA review and comparison of the Enbridge action plan to those of other gas utilities in Ontario, Enbridge may be requested to make modifications or enhancements to the Action Plan. These changes may impact the components and contents of the draft Action Plan and the forecast costs to implement the plan.

32. Enbridge's forecast 2012 revenue requirement associated with implementing the Action Plan is $3.8 million, based upon total forecast costs of approximately $5.8 million, comprised of $3.7 million of O&M costs and $2.1 million of capital costs. The derivation of this revenue requirement amount is set out at Appendix C, to this exhibit.

Witnesses: C. Clark
L. Lawler

Evaluation of Criteria for Z factor

33. The following are criteria to be met for Z factor treatment:

a. The event must be causally related to an increase/decrease in cost;
b. The cost must be beyond the control of the Company's management, and is not a risk in respect of which a prudent utility would take risk mitigation steps;
c. The cost increase/decrease must not otherwise be reflected in the per customer revenue cap;
d. Any cost increase must be prudently incurred; and
e. The cost increase/decrease must meet the materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event).

34. Each of the above-noted criteria is evaluated below with reference to the issue of Cross Bore Action Plan costs.

a. *The event must be causally related to an increase/decrease in cost*
There is a direct link between the TSSA Directive (which itself is directly related to newly identified safety issues associated with cross bores) and the increases in Enbridge's costs (as compared to the costs that are included in the base revenue requirement under its IRM plan) that will result from the implementation of the Cross Bore Action Plan.

b. *The cost must be beyond the control of the Company's management, and is not a risk in respect of which a prudent utility would take risk mitigation steps*
Having become aware of the potential safety risks associated with cross bores, and the industry-wide efforts to address cross bores, it was prudent and appropriate for Enbridge to take steps to address and manage potential

risks. Those activities will be mandatory as of October 31, 2011, as a result of the TSSA Directive. As such, the costs are beyond management's control.

c. *The cost increase/decrease must not otherwise be reflected in the per customer revenue cap*

The 2012 costs and revenue requirement associated with the Company's Cross Bore Action Plan are not included in base rates (revenue requirement), because the activities that are required under the Cross Bore Action Plan are new activities since the time when base rates were established for this IRM term.

d. *Any cost increase must be prudently incurred*

Enbridge's Cross Bore Action Plan is consistent with the CGA "white paper" and industry best practices. The costs associated with Enbridge's Cross Bore Action Plan are appropriate and will be prudently incurred. They represent reasonable costs to address newly identified safety issues, and to comply with a mandatory directive from the utility's safety regulator, the TSSA. As noted above, customers have previously benefitted from the cost savings associated with trenchless installation techniques which may have inadvertently led to some cross bores.

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

The Company's forecast 2012 revenue requirement of $3.8 million associated with its Cross Bore Action Plan exceeds the $1.5 million materiality threshold.

Proposed Mechanics of the Requested Cost Recovery

35. As noted above, the Company's forecast Cross Bore Action Plan revenue requirement of $3.8 million, all of which is an increase over the revenue requirement included in base rates, meets the Z factor criteria. The exact 2012 revenue requirement amount will only be known after the 2012 year is complete and all underlying costs are known.

36. Enbridge proposes that the forecast 2012 revenue requirement of $3.8 million associated with its Cross Bore Action Plan be included in the revenue requirement as a Z factor item in the current application. Further, given the timing and the potential variability associated with the actual costs and revenue requirement associated with this item, Enbridge proposes that the Z factor for Cross Bore Action Plan revenue requirement should be coupled with a Cross Bore Costs Variance Account.

37. Once the 2012 costs and associated revenue requirement amount for the Cross Bore Action Plan are known, then any variance from the forecast revenue requirement amount of $3.8 million will be transferred to this variance account for future refund to or collection from ratepayers. This process will ensure that the net recovery in rates is fully aligned with the costs ultimately incurred by Enbridge.

Witnesses: C. Clark
L. Lawler

Fuels Safety Program	Ref. No.: FS-188-11	Rev. No.:
OIL AND GAS PIPELINE SYSTEMS CODE ADOPTION DOCUMENT - AMENDMENT	Date: August 31, 2011	Date:

IN THE MATTER OF:
THE TECHNICAL STANDARDS AND SAFETY ACT, 2000, S.O. 2000, c. 16 (the "Act")

- and -

ONTARIO REGULATION 223/01 (Codes and Standards Adopted by Reference) made under the Act
- and -
ONTARIO REGULATION 210/01 (Oil and Gas Pipeline Systems) made under the Act

Subject: Cross Bore Issue - Clearing Blocked Sewer Service Lines. Amendment to the Oil and Gas Pipeline Systems Code Adoption Document

Sent to: Gas Advisory Council, Risk Reduction Group-Pipelines, Posted on TSSA's Web-Site, other Stakeholders.

The Director of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems), pursuant to section 8 of Ontario Regulation 223/01 (Codes and Standards Adopted by Reference), hereby provides notice that the Oil and Gas Pipeline Systems Code Adoption Document published by the Technical Standards and Safety Authority and dated June1, 2001, as amended, is further amended as follows:

1. Clause 12.10.13.1 of CSA Z662-07 is amended by adding the following:

   12.10.13.1.3 Natural gas distributors shall incorporate into the procedures for managing the integrity of pipeline systems required in clause 12.10.13.1.2 an action plan that includes:

   a) a description of the steps to mitigate the potential of penetration of sewer lines by a natural gas pipeline during trenchless installation,

   b) a program that raises stakeholder awareness of the potential safety issues that could arise when attempting to clear a blocked sewer service line beyond the outside walls of a building, and

   c) an assessment of potential risks and a plan to mitigate these risks.

   This action plan shall be completed and available to TSSA for inspection by October 30, 2011

2. <u>The above amendment is effective immediately.</u>

Background

A potential safety situation could arise when home owners or administrators of commercial, institutional or industrial buildings attempt (by themselves or by calling a contractor) to clear a blocked sewer service line beyond the outside wall of the building. The issue is that natural gas pipelines installed using trenchless practices may have inadvertently penetrated the sewer line.

A natural gas pipeline that has penetrated a sewer line may be undetected for a long period of time. Clearing the sewer service line with rotating equipment or water jet equipment could damage the gas pipeline and result in a leak of natural gas into the sewer line, posing an immediate safety risk.

Dated at Toronto this August 31, 2011.

APPROVED BY:

John Marshall,
Director, Ontario Regulation 210/01 (Oil and Gas Pipeline Systems), made under the *Technical Standards and Safety Act, 2000*

Utility Cross Bores Action Plan for Compliance to CAD Amendment FS-188-11

Final Draft

Sept. 19, 2011

Agenda

1. Introduction and Overview

2. TSSA CAD Requirements

3. Enbridge Sewer Safety Program Components:

   3.1 Assessment of Risks

   3.2 Response Plan

   3.3 Education/Awareness of Response Plan and Results

   3.4 New Construction Mitigation Procedures

   3.5 Legacy Work

   3.6 Records

   3.7 Research and Development

Introduction & Overview:

ENBRIDGE

- Trenchless technologies permit the installation of utilities without the need for open trenching
- Various utility owners use trenchless technologies for installation of underground facilities
- Various municipalities mandated the of trenchless technologies for underground utility installations
- Trenchless technologies reduce:
  – installation and restoration costs
  – disruption to traffic and properties
  – environmental impact
  – customer disruption and complaints

Introduction and Overview

A crossbore is:

- Defined as an unintended intersection of an existing underground utility by a second utility than can occur during construction that uses trenchless technologies
- Integrity of one or both utilities is compromised
- Safe unless compromised by sewer cleaning equipment
- A broader issue than just natural gas

Overview, con’t

Two Basic Issues

- Not creating new cross bores
  - i.e. properly locating and marking sewer lines before construction so the lines can be avoided like any other underground utility
- Understanding where cross bores exist due to historical practices

In the United States

- 50 states, 50 laws
- Requirements generally reactive to an incident (Minnesota)
- American Gas Association white paper on cross bore prevention
- Cross Bore Safety Association promoting awareness and mitigation strategies (Enbridge is a lead on this)

In Canada

- Ontario Regional Common Ground Alliance best practices adopted
  - Make new sewer installations locatable
  - Data sharing
- Canadian Gas Association task force white paper

Overview - Regulatory Environment

United States

- PHMSA Sub Part P 49 CFR 192 Distribution Integrity Management Program
  - "Enhance safety by indentifying and reducing pipeline risks"
- Minnesota Department of Pipeline Safety mandated investigations
- Virginia mandated municipal participation in One Call system and provision of sewer locates

Canada

- CAN CSA Z662-07 Annex M.8.1
  - "Gas distribution companies should identify and document hazards that can lead to a failure or damage incident with significant consequences."
- New CAD requirement by TSSA effective Aug. 30, 2011 specific to issue

TSSA CAD Components

Fuels Safety Program	Ref. No.: FS-188-11	Rev. No.:
OIL AND GAS PIPELINE SYSTEMS CODE ADOPTION DOCUMENT - AMENDMENT	Date: August 31, 2011	Date:

IN THE MATTER OF:
THE TECHNICAL STANDARDS AND SAFETY ACT, 2000, S.O. 2000, c. 16 (the "Act")

- and -

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- and -
ONTARIO REGULATION 210/01 (Oil and Gas Pipeline Systems) made under the Act

Subject: Cross Bore Issue - Clearing Blocked Sewer Service Lines. Amendment to the Oil and Gas Pipeline Systems Code Adoption Document

Sent to: Gas Advisory Council, Risk Reduction Group-Pipelines, Posted on TSSA's Web-Site, other Stakeholders.

The Director of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems), pursuant to section 8 of Ontario Regulation 223/01 (Codes and Standards Adopted by Reference), hereby provides notice that the Oil and Gas Pipeline Systems Code Adoption Document published by the Technical Standards and Safety Authority and dated June1, 2001, as amended, is further amended as follows:

1. Clause 12.10.13.1 of CSA Z662-07 is amended by adding the following:

   12.10.13.1.3 Natural gas distributors shall incorporate into the procedures for managing the integrity of pipeline systems required in clause 12.10.13.1.2 an action plan that includes:

   a) a description of the steps to mitigate the potential of penetration of sewer lines by a natural gas pipeline during trenchless installation,

   b) a program that raises stakeholder awareness of the potential safety issues that could arise when attempting to clear a blocked sewer service line beyond the outside walls of a building, and

   c) an assessment of potential risks and a plan to mitigate these risks.

   This action plan shall be completed and available to TSSA for inspection by October 30, 2011

2. The above amendment is effective immediately.

Background

A potential safety situation could arise when home owners or administrators of commercial, institutional or industrial buildings attempt (by themselves or by calling a contractor) to clear a blocked sewer service line beyond the outside wall of the building. The issue is that natural gas pipelines installed using trenchless practices may have inadvertently penetrated the sewer line.

A natural gas pipeline that has penetrated a sewer line may be undetected for a long period of time. Clearing the sewer service line with rotating equipment or water jet equipment could damage the gas pipeline and result in a leak of natural gas into the sewer line, posing an immediate safety risk.

Dated at Toronto this August 31, 2011.

APPROVED BY: John Marshall

John Marshall,
Director, Ontario Regulation 210/01 (Oil and Gas Pipeline Systems), made under the *Technical Standards and Safety Act, 2000*

Understanding the Cross Bore Risk

- Potential danger when third party attempts to clear unidentified blockage
- Natural gas escapes into enclosed structures with potential ignition sources

In the United States

- More than 20 significant incidents in the last 10 years

In Canada

- No documented incidents causing personal injury or significant property damage
- Initially thought not to be an issue (cold climate, deep sewers)
- Increased recognition of potential risks among Canadian gas utilities



Assessing the Risk

ENBRIDGE

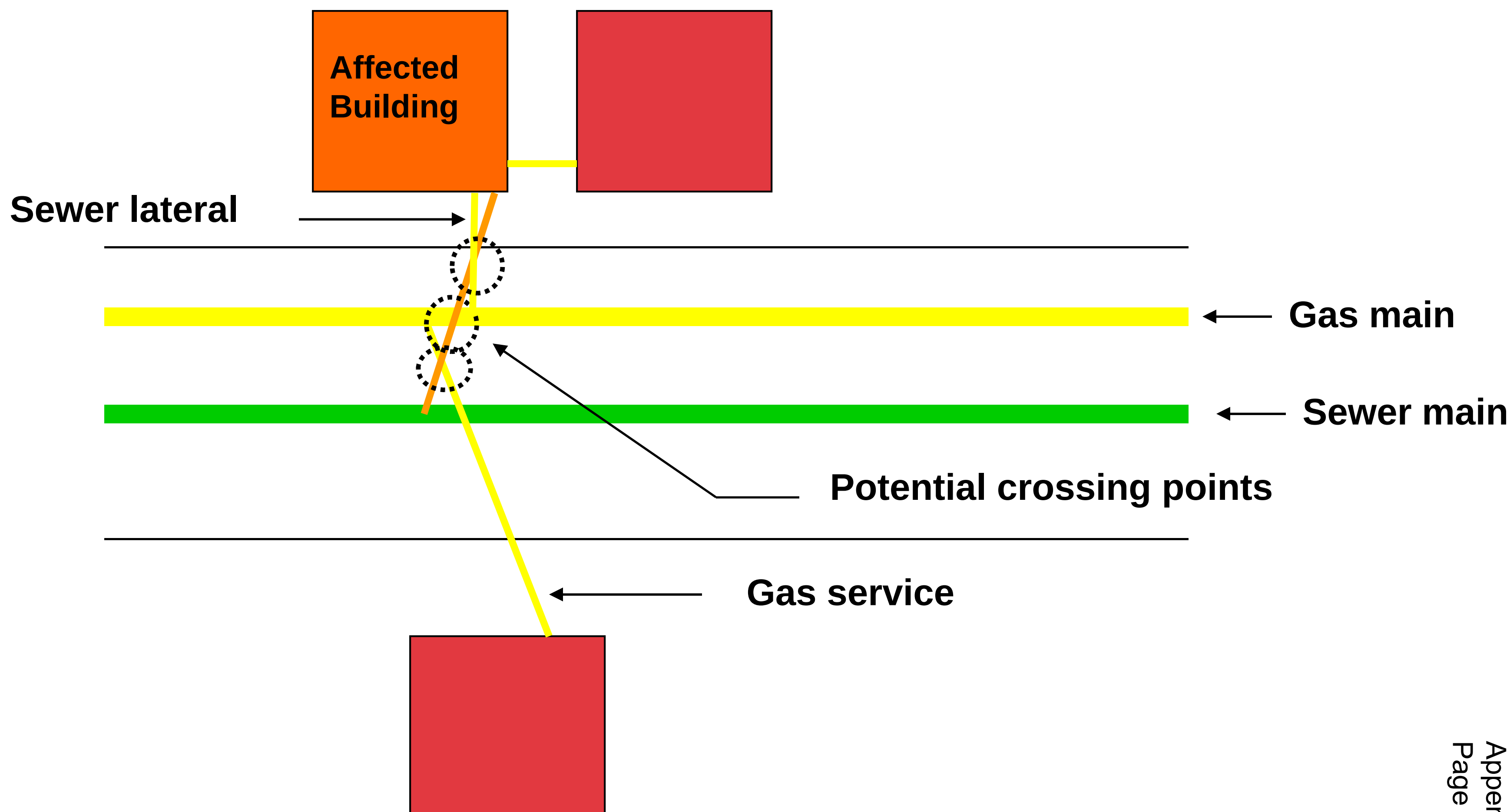
Quantify existing risk and future risk with status quo approach

- Low frequency high consequence event
- Nature of construction practices have created the condition
  - Trenchless technologies utilized since the 1970's
  - Sewer lines in Ontario may be shallow despite cold winters due to unusual conditions (often site specific)
  - Multiple sewer configurations which are difficult to predict
- Sewer lines are not easily locatable (not tonable and few or nonexistant as-built records)

Some unknowns:

- What are the factors that cause a cross bore to be likely?
- How often does a sewer clearing operation result in a gas leak?
- How can we ensure municipal and plumber uptake of any program?

Assessing the Risk



Where do cross bores occur? Why? Research Phase

Main contributing causes of having shallow clearance between sewer laterals and gas utilities are believed to be:

Macro Factors

- Areas with a high water table, or surrounding identified lakes *
- Areas with low drift thickness cover *
- Mobile home communities *
- Known areas with shallow sewer mains
- Areas where the gas line is buried deeper than usual
- Localized elevation changes (Terraced properties)

Micro Factors

- Homes with shallow or no basements
- Privately owned sewer systems
- Sewer laterals that exit other than the basement floor

Response Plan

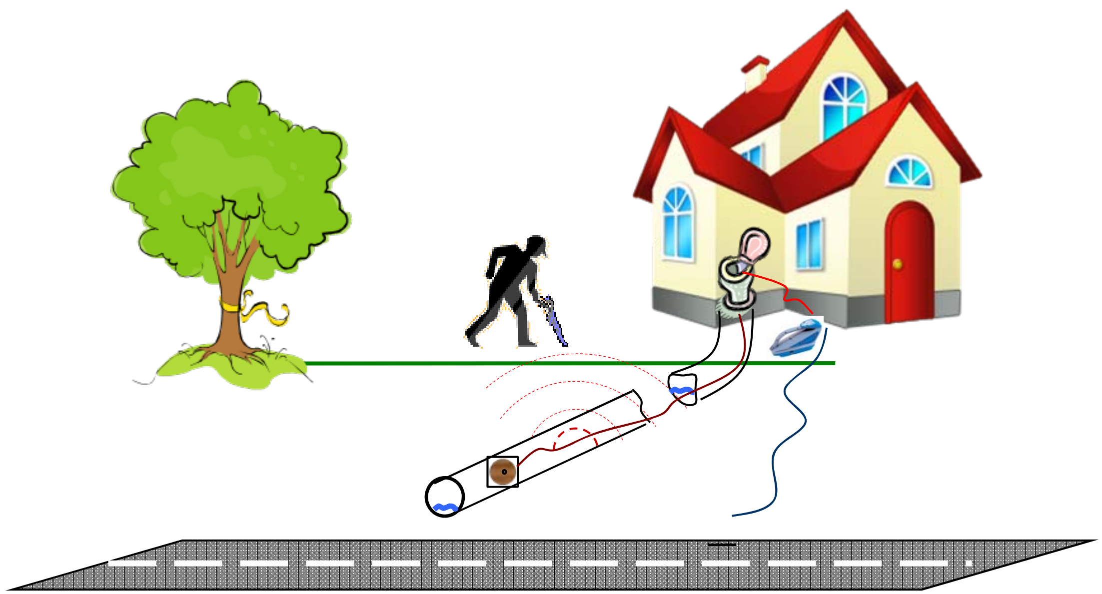
ENBRIDGE

ON1CALL
CALL BEFORE YOU DIG

- Call Ontario One Call for a sewer safety inspection prior to unblocking a sewer beyond the walls of the building (24/7, free service)
- EGD representative will arrive within 2 hours or at a prearranged time to provide the inspection

Response Plan

- EGD representative will determine the location of the natural gas lines and the sewer service line and provide the requestor a copy of the sewer safety inspection report



- Report will either indicate the inspection passed or DANGER DO NOT PROCEED

Natural Gas Sewer Safety Inspection Report

Page 1 of 2

SLA Company Logo	Natural Gas Sewer Safety Inspection - Primary Sheet NOT VALID FOR EXCAVATION* TO BE USED FOR SEWER SERVICE LINE CLEARING ONLY			Request #:
	Tel:	Fax:	Toll Free:	Email:
Requested By:	Company (if applicable):	Appt. Date (mm/dd/yyyy):	Appt. Time (HH:MM):	
Tel:	Fax:	Email:	On-Site Meeting Required:	
Address:			Municipality:	
Caller's Remarks:	Building Usage: ☐ Residential ☐ Mixed ☐ Industrial	☐ Commercial ☐ Institutional ☐ Other	Requestor: ☐ Building Owner/Tenant ☐ Private Contractor ☐ Municipal Representative	
Type of Work:				
Records Reference:				
☐ Network X #				
☐ Datapak				
Field Notes:				
Other:				
DPT Remarks:				

INSPECTION PASSED
An investigation has identified that there are no conflicts between the sewer service line and the Enbridge Gas Distribution utility within the located area.
CAUTION: THIS APPLIES TO THE ENBRIDGE GAS DISTRIBUTION LOCATED UTILITY ONLY

Inspection Type:				Remarks:
Type #1 – Recorded as Cleared	☐ USED	☐ PASSED	☐ FAILED	
Type #2 – Installation Dates	☐ USED	☐ PASSED	☐ FAILED	
Type #3 – Proximity Test	☐ USED	☐ PASSED	☐ FAILED	
Type #4 – Video Inspection	☐ USED	☐ PASSED	☐ FAILED	

Warning: This Natural Gas Sewer Safety Inspection report does not constitute a Locate and is not valid for any type of excavation* i.e. dig, bore, trench, grade, excavate or break ground with mechanical equipment or explosives.

Caution: Read Important Information on reverse side.

Caution: Sewer service line clearing work should not extend to another sewer service line without a new Natural Gas Sewer Safety Inspection.

Caution: The Natural Gas Sewer Safety Inspection only inspects for the possible presence of Enbridge Gas Distribution's gas lines inadvertently installed through sewer service lines. The natural gas sewer safety inspection does not inspect for the presence of any other privately owned or utility owned conduit, cable or pipe. If you believe that such a utility is installed through the sewer service line please contact the utility owner.

Caution: The person performing sewer clearing work should have a copy of this inspection report on the job site or perform a sewer service line video inspection before performing any sewer service line clearing work with sewer/drain cleaning equipment, of rotating type or pressurized water-jetting type.

Caution: The Natural Gas Sewer Safety Inspection is not valid for any excavation and is to be used for sewer service line clearing only. Any change to the nature of the work required to be completed may require a Locate.

For all Locate requests, including remarks, contact Ontario One Call at 1-800-400-2255 or www.on1call.com

Locator Name:	Start Time:	☐ Mark & Fax ☐ Left on Site ☐ Emailed
ID #:	End Time:	Locate Received by: Print:
Date (mm/dd/yyyy):	Total Hours:	Signature:

A copy of this Primary Sheet and Auxiliary Sheet(s) should be on site and reviewed by the requestor before sewer clearing work operations.

Page 1 of 2

SLA Company Logo	Natural Gas Sewer Safety Inspection - Primary Sheet NOT VALID FOR EXCAVATION* TO BE USED FOR SEWER SERVICE LINE CLEARING ONLY			Request #:
	Tel:	Fax:	Toll Free:	Email:
Requested By:	Company (if applicable):	Appt. Date (mm/dd/yyyy):	Appt. Time (HH:MM):	
Tel:	Fax:	Email:	On-Site Meeting Required:	
Address:			Municipality:	
Caller's Remarks:	Building Usage: ☐ Residential ☐ Mixed ☐ Industrial	☐ Commercial ☐ Institutional ☐ Other	Requestor: ☐ Building Owner/Tenant ☐ Private Contractor ☐ Municipal Representative	
Type of Work:				
Records Reference:				
☐ Network X #				
☐ Datapak				
Field Notes:				
Other:				
DPT Remarks:				

DANGER DO NOT PROCEED
An investigation has identified that there is a conflict between the sewer service line and the Enbridge Gas Distribution utility within the located area. An Enbridge Supervisor will attend and arrange to remedy the conflict.
CAUTION: THIS APPLIES TO THE ENBRIDGE GAS DISTRIBUTION LOCATED UTILITY ONLY

Inspection Type:				Remarks:
Type #1 – Recorded as Cleared	☐ USED	☐ PASSED	☐ FAILED	
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Locator Name:	Start Time:	☐ Mark & Fax ☐ Left on Site ☐ Emailed
ID #:	End Time:	Locate Received by: Print:
Date (mm/dd/yyyy):	Total Hours:	Signature:

A copy of this Primary Sheet and Auxiliary Sheet(s) should be on site and reviewed by the requestor before sewer clearing work operations.

Response Plan

SSI Manual

- If Danger Do Not Proceed sticker is affixed, call will be elevated to EGD Operations Supervisor to determine if we need to dig to eliminate the possibility of a crossbore

- See Natural Gas Sewer Safety Inspection document

Awareness of Response Plan

- Public campaign with press release Sept 2010, bill insert October 2010, EGD website posting, and Employee News

- Newspaper advertisements Nov 2010 and Google ads (when certain words searched in franchise), and bill envelope message.

- Worked with other gas distribution companies in Ontario and Canada to assist with risk assessment, education, awareness and response programs (promote consistency)

SSI Letter 1

SSI Letter 2

SSI Letter 3

Brochure

Brochure 2

Newspaper Add

Awareness of Response Plan

- Bill inserts in March 2011, radio adds in April and continued awareness activities (equipment rental companies, insurance companies, plumbing and drain cleaning associations, community colleges)
- Continue to work with Municipalities to ensure operational effectiveness and promote consistency with due consideration for varied approaches to ownership of sewer service line

SSI Letter 1
SSI Letter 2
SSI Letter 3
Brochure
Brochure 2
Newspaper Add

Awareness Results

- Customer Awareness Survey Results, Q4 2010
- 720 customers polled
  - 21% recalled hearing / seeing something about sewer safety program
  - 68% of 21% recalled seeing information in gas bill insert
  - 38% indicated they would call Enbridge if they had a blocked sewer that had to be cleared
  - 36% indicated they would call a plumber
  - 2% indicated they would call Ontario One Call

New Construction Procedures

Solution to New Construction Installations

Education
- Construction Crews
- TT Equipment Mfg.
- Government & Agencies

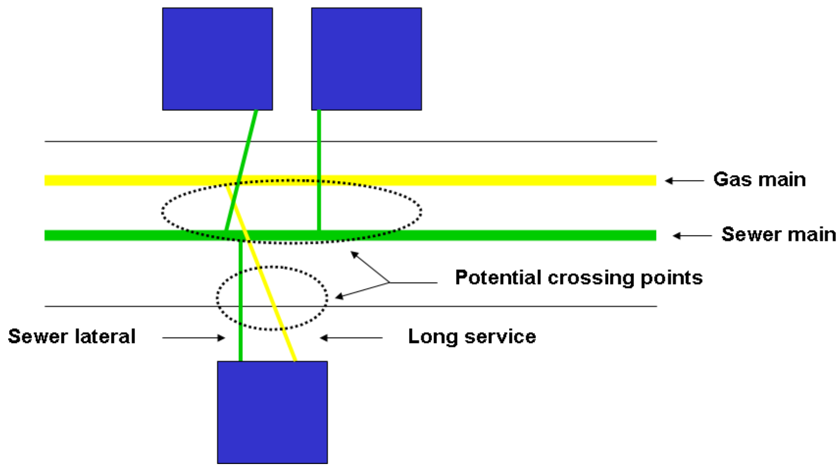
Investigation
- Pre-Inspections
- Sewer Locates

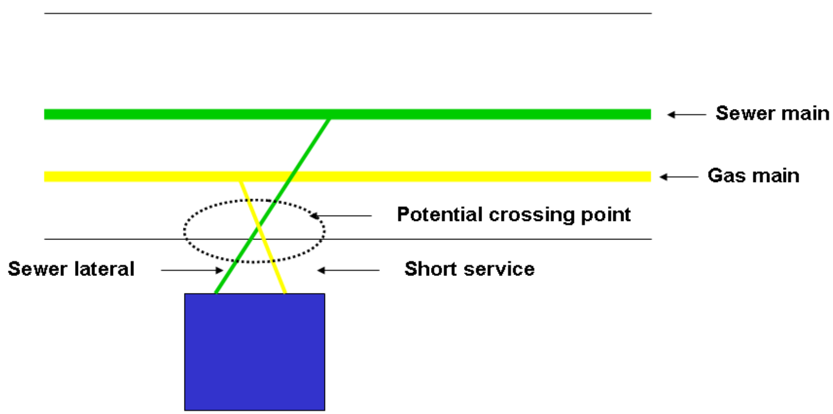
Installation
- Minimum Depth Bores
- Daylight Utilities
- Camera Inspection
- Open Trench

- Detailed field review of area to identify any of the main contributing factors showing a possible shallow sewer lateral.
- Municipal sewer lateral locate requested
- Private sewer lateral locates ordered

Note: Sample of one of the contributing causes

New Construction Procedures

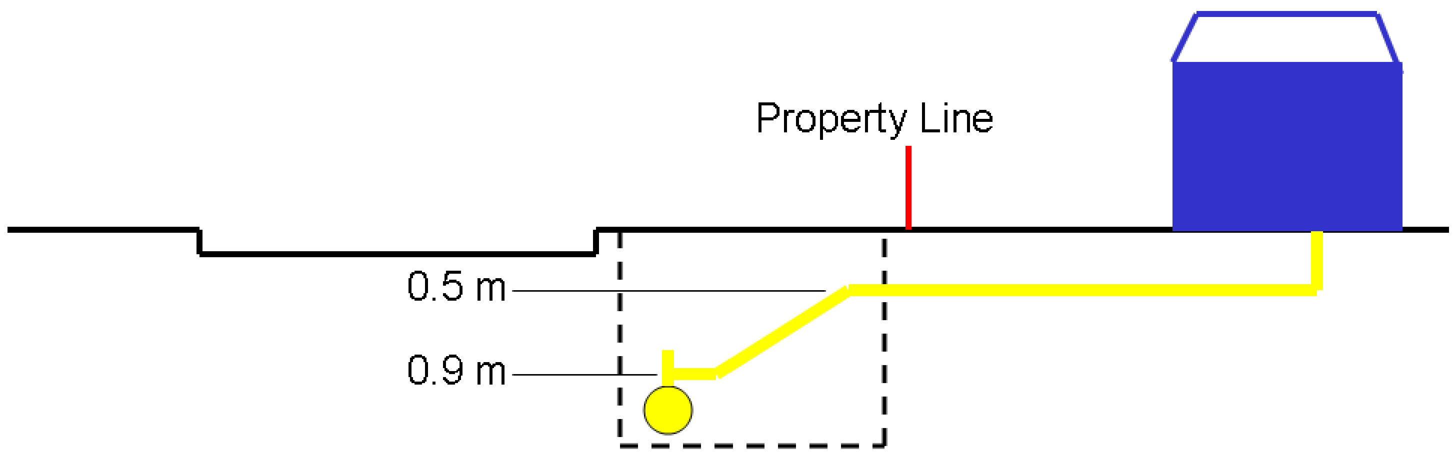




- Field reviews are set to take into consideration macro and micro factors of service install location
- Buildings on opposite side of installation address may also be at considerable risk.

New Construction Procedures

- Based on the field review if no sewer lateral locate is required because of absence of contributing factors, service lines can be installed as long as transitioned to minimum depths.

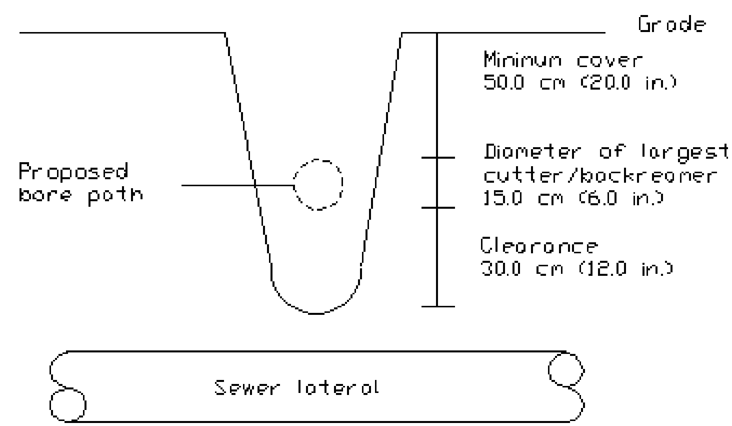


New Construction Procedures

- When gas line will be installed by trenchless technology and will be within 1 m (3.3 ft) of the sewer lateral in any direction. The bore path must be daylighted as illustrated.

Example Calculation of Excavation Depth
(Service Installation Crossing the Sewer Lateral)

Minimum cover	= 50.0 cm (20.0 in)
Diameter of cutter/backreamer	= 15.0 cm (6.0 in)
Clearance factor	= 30.0 cm (12.0 in)
Total (minimum depth of daylight hole)	= 95.0 cm (38.0 in)



Legacy Investigations

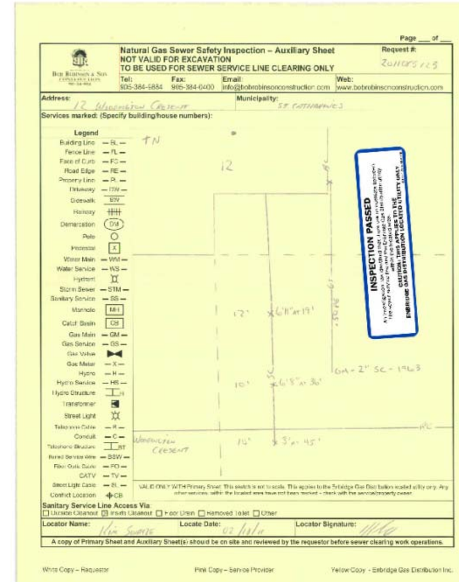
ENBRIDGE

Perform approximately 2000 sewer lateral investigations per year

- Began by checking addresses identified as having a high potential of having a cross bore, however success rate was low
- Now performing legacy investigations on streets / neighborhoods where a cross bore has been identified
- Also working with municipalities to understand shallow sewer installation locations

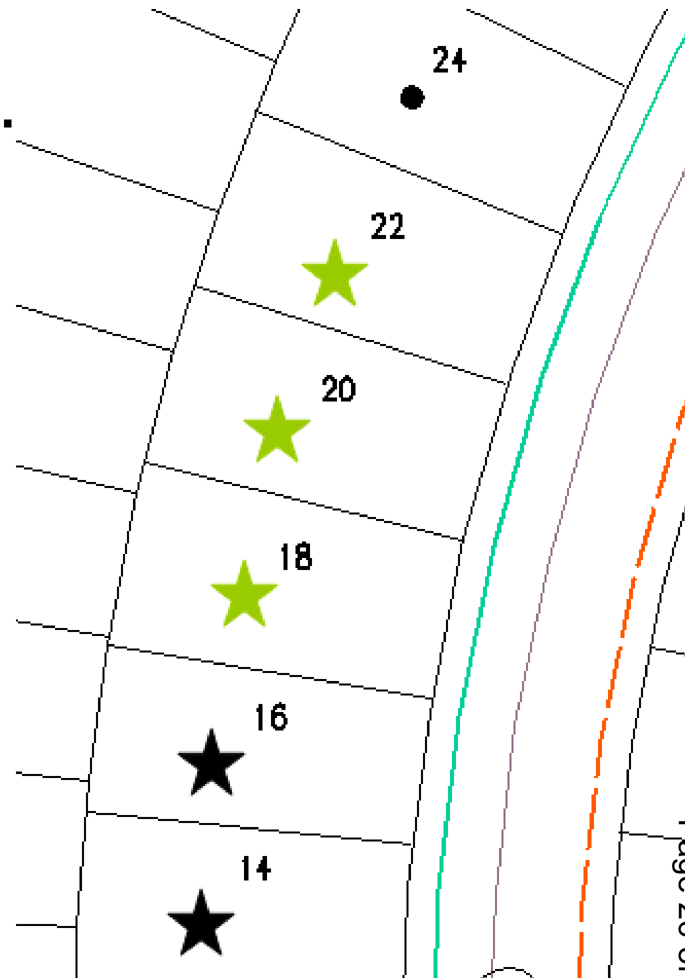
Legacy Investigations - Data Sharing

- Developed standard data sharing agreement for use with Municipalities. Type, level of detail, format, etc. (draft)
- We provide sewer lateral location information to sewer owners and they, in turn, provide areas they have cleared
- Avoids duplication of work and is cost effective
- We have included municipal standards for condition assessment and coding in sewer inspection service provider contracts



Records

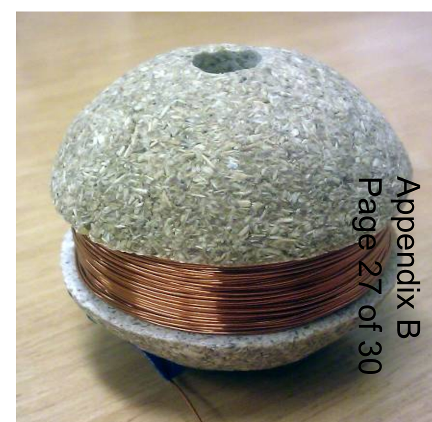
- Determining how to record findings, update systems etc. to move to office clears in the future
- Recording method of installation going forward



Research & Development

ENBRIDGE

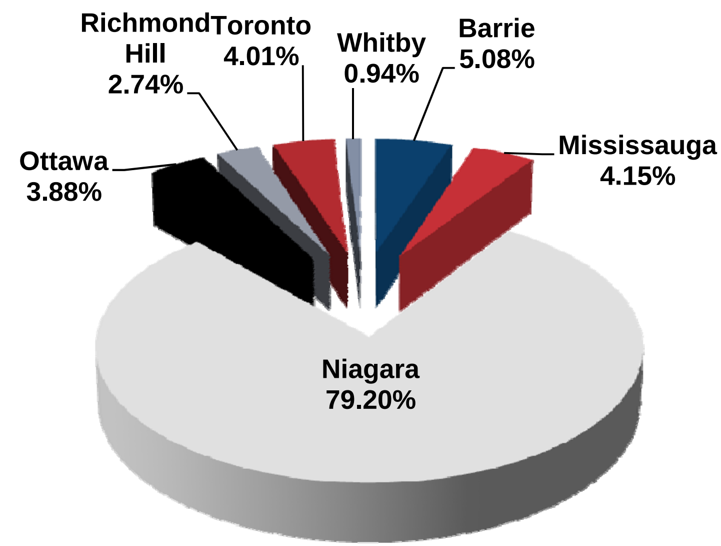
- Commissioned impact testing study of sewer water jetting equipment with University of Waterloo
- Determine nozzle types, pressures and equipment that will not damage gas lines in sewer pipes
- Study completion and report Q4 2011
- Field testing of ultrasonic sewer locating device scheduled fall 2011
- Bio Ball type 2
  - development of ball that will pass through “P” traps in progress



Sewer Safety Program Results 2010

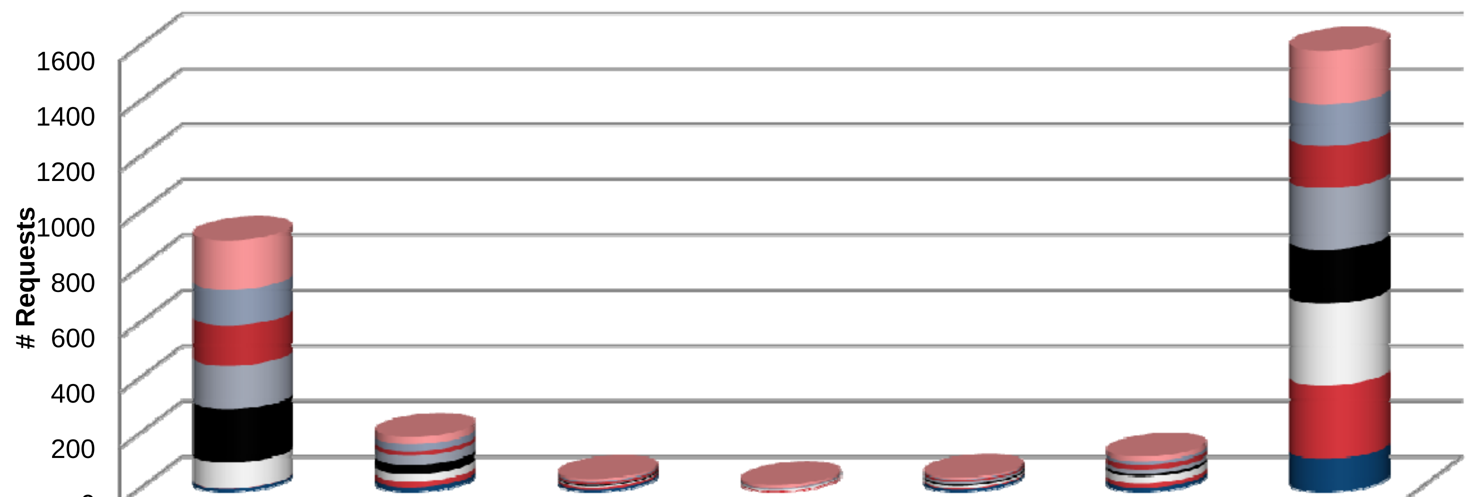
- 1495 requests through Ontario One Call
- 45 investigative digs
- 24 cross bores found in laterals
- 3 non gas utility cross bores found (hydro duct and communication cables)
- 30 cross bores removed from sewer mains
- 1854 legacy investigations completed
  - 0 cross bores found from legacy work using risk criteria
  - 1 cross bore found from reactive legacy work (investigations in areas where cross bore found by third party)
- Working with municipalities to ensure operational effectiveness and minimize costs
- Ongoing education and awareness communications to increase uptake

2010 Sewer Lateral Locates Requested (%)



Sewer Safety Inspection Requests Through Ontario One Call

2011 Sewer Lateral Requests by Area per Month



	Toronto	Mississauga	Richmond Hill	Whitby	Barrie	Ottawa	Niagara
August	178	27	8	9	6	18	195
July	129	25	5	1	3	12	149
June	146	15	7	1	6	18	153
May	157	35	2	4	9	14	221
April	193	33	4		6	10	197
March	93	27	4	5	8	25	294
February	1	20	8	3	4	16	265
January	11	16	8		9	14	119

Questions?

CAPITAL STRUCTURE
CROSS BORE / SEWER LATERAL PROGRAM Z FACTOR CALCULATION

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	(2,714.2)
8.	Rate base	911.4
9.	Indicated rate of return	(297.81)%
10.	(Def.) / suff. in rate of return	(305.39)%
11.	Net (def.) / suff.	(2,783.3)
12.	Gross (def.) / suff.	(3,774.0)

RATE BASE
CROSS BORE / SEWER LATERAL PROGRAM Z FACTOR CALCULATION

($000's)

Line No.		2012
	Property, plant, and equipment	
1.	Cost or redetermined value	923.0
2.	Accumulated depreciation	(11.6)
3.		911.4
	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	911.4

INCOME
CROSS BORE / SEWER LATERAL PROGRAM Z FACTOR CALCULATION

($000's)

Line No.		2012
	Revenue	
1.	Gas sales	-
2.	Transportation of gas	-
3.	Transmission and compression	-
4.	Other operating revenue	-
5.	Other income	-
6.	Total revenue	-
	Costs and expenses	
7.	Gas costs	-
8.	Operation and Maintenance	3,681.7
9.	Depreciation and amortization	49.0
10.	Municipal and other taxes	-
11.	Total costs and expenses	3,730.7
12.	**Utility income before inc. taxes**	(3,730.7)
	Income taxes	
13.	Excluding interest shield	(1,005.9)
14.	Tax shield on interest expense	(10.6)
15.	Total income taxes	(1,016.5)
16.	**Ontario utility net income**	(2,714.2)

TAXABLE INCOME AND INCOME TAX EXPENSE
CROSS BORE / SEWER LATERAL PROGRAM Z FACTOR CALCULATION

($000's)

Line No.		2012
1.	Utility income before income taxes	(3,730.7)
	Add Backs	
2.	Depreciation and amortization	49.0
3.	Large corporation tax	-
4.	Other non-deductible items	-
5.	Any other add back(s)	-
6.	Total added back	49.0
7.	Sub total - pre-tax income plus add backs	(3,681.7)
	Deductions	
8.	Capital cost allowance - Federal	150.5
9.	Capital cost allowance - Provincial	150.5
10.	Items capitalized for regulatory purposes	-
11.	Deduction for "grossed up" Part V1.1 tax	-
12.	Amortization of share and debt issue expense	-
13.	Amortization of cumulative eligible capital	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-
15.	Any other deduction(s)	-
16.	Total Deductions - Federal	150.5
17.	Total Deductions - Provincial	150.5
18.	Taxable income - Federal	(3,832.2)
19.	Taxable income - Provincial	(3,832.2)
20.	Income tax provision - Federal	(574.8)
21.	Income tax provision - Provincial	(431.1)
22.	Income tax provision - combined	(1,005.9)
23.	Part V1.1 tax	-
24.	Investment tax credit	-
25.	Total taxes excluding tax shield on interest expense	(1,005.9)
	Tax shield on interest expense	
26.	Rate base as adjusted	911.4
27.	Return component of debt	4.43%
28.	Interest expense	40.4
29.	Combined tax rate	26.250%
30.	Income tax credit	(10.6)
31.	**Total income taxes**	(1,016.5)

REVENUE REQUIREMENT
CROSS BORE / SEWER LATERAL PROGRAM Z FACTOR CALCULATION

($000's)

Line No.		2012
	Cost of capital	
1.	Rate base	911.4
2.	Required rate of return	7.58%
3.	Cost of capital	69.1
	Cost of service	
4.	Gas costs	-
5.	Operation and Maintenance	3,681.7
6.	Depreciation and amortization	49.0
7.	Municipal and other taxes	-
8.	Cost of service	3,730.7
	Misc. & Non-Op. Rev	
9.	Other operating revenue	-
10.	Other income	-
11.	Misc, & Non-operating Rev.	-
	Income taxes on earnings	
12.	Excluding tax shield	(1,005.9)
13.	Tax shield provided by interest expense	(10.6)
14.	Income taxes on earnings	(1,016.5)
	Taxes on (def) / suff.	
15.	Gross (def.) / suff.	(3,774.0)
16.	Net (def.) / suff.	(2,783.3)
17.	Taxes on (def.) / suff.	990.7
18.	**Revenue requirement**	3,774.0
	Revenue at existing Rates	
19.	Gas sales	0.0
20.	Transportation service	0.0
21.	Transmission, compression and storage	0.0
22.	Rounding adjustment	0.0
23.	Revenue at existing rates	0.0
24.	**Gross revenue (def.) / suff.**	(3,774.0)

2012 PROPOSED RATES

1. This evidence outlines the Company's proposal with respect to 2012 rates within its Revenue Cap per Customer Incentive Regulation Model approved in EB-2007-0615 (Test Year 2008). The evidence lays out the development of the proposed 2012 rates including the proposed recovery of the 2012 revenue requirement.

2. The Company is seeking Board approval of each of the following:
   a. recovery of the 2012 revenue requirement from all elements of the Company's rates;
   b. the proposed rates for each customer class; and
   c. the Rate Handbook filed under Exhibit B, Tab 3, Schedule 2.

3. The Rate Handbook filed under Exhibit B, Tab 3, Schedule 2 reflects proposed changes to Rate 200 (Wholesale Service) with respect to the provisions for interruptible service. Except for the proposed changes to Rate 200, all other components of the Rate Handbook filed under this exhibit remain as approved in EB-2011-0296 (October 1, 2011 QRAM).

Components of the 2012 Revenues

4. The derivation of the Company's 2012 revenues reflecting the Revenue Cap per Customer incentive regulation model is presented at Exhibit B, Tab 1, Schedule 2, page 1. Row 29 of that exhibit represents total proposed revenues for 2012 in the amount of $2,544.29 million.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

5. As shown at rows 27, 28, and 29, the 2012 proposed revenues consist of:

2012 Distribution Revenues	$1,028.79
2012 Gas Cost to Operations	$1,515.50
2012 Total Revenues	$2,544.29

6. The 2012 distribution revenues are comprised of: a) 2012 base distribution revenue in the amount of $839.99 million (Row 18), which is determined using the Revenue Cap per Customer incentive regulation escalation formula, b) distribution related Y factor revenues in the amount of $167.30 million (Row 23) and c) distribution related Z factor revenues in the amount of $21.50 million (Row 26).

7. The 2012 Gas Cost to Operations reflects pass-through of gas supply costs such as commodity, upstream transportation, contracted storage, and load balancing. The Gas Cost to Operations evidence is filed at Exhibit B, Tab 4, Schedule 1.

2012 Rate Impacts

8. The Company has designed rates to recover the proposed 2012 revenues of $2,544.29 million. Table 1 below provides a summary of the resulting average rate impacts by rate class. Rate impacts for customers taking service under bundled rates are expressed on a T-service basis. Rate impacts for customers taking service under unbundled rates are expressed on a delivery rate basis.

9. The proposed rate impacts are relative to the existing October 1, 2011 QRAM Board approved rates filed under EB-2011-0296 and reflect the proposed 2012 revenue requirement, the proposed 2012 volumetric forecast, and the proposed 2012 Gas Cost to Operations budget.

Table 1: 2012 Proposed Average Rate Impacts

Rate Class	T-Service Rate Impact
1	2.3%
6	0.9%
9	1.6%
100	0.0%
110	0.3%
115	-1.3%
135	0.4%
145	-1.2%
170	-1.4%
200	-0.2%
	Delivery Rate Impact
125	1.4%
300	1.4%

10. The 2012 rate impacts are lower for all rate classes than the threshold levels requiring supplementary explanation as outlined in the EB-2007-0615 Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, page 31.

Rate Design Exhibits

11. Rate design exhibits are filed at Exhibit B, Tab 3, Schedules 3 to 9. The exhibits present the proposed recovery of the 2012 revenues. The schedules are organized in the following manner:

    a) Schedule 3 of Exhibit B, Tab 3 summarizes, by rate class, and rate component, the revenues at proposed rates which are forecast to be recovered in 2012. Schedule 4 displays the revenues by rate class and component and by unit rate in conjunction with the associated volumes.
    b) Schedule 5 summarizes the revenues shown in Schedule 3 and presents the unbilled revenues at proposed rates.
    c) Schedule 6 compares the current unit rates from EB-2011-0269 (October 1, 2011 QRAM) to the proposed unit rates.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

d) Schedule 7, pages 1 and 2 show the derivation of gas supply, gas supply load balancing, and transportation rates. Page 3 depicts the generation of the seasonal and interruptible credits.
e) Schedule 8 shows the detailed revenue calculations by rate class.
f) Annual bill comparisons indicating the impact of the Company's proposed rates on typical rate class customers relative to the EB-2011-0269 (October 1, 2011 QRAM) rates are shown at Schedule 9.

12. The following paragraphs outline the process the Company used to design its commodity, transportation, load balancing, and distribution rates.

Rate Design: Gas Supply Revenues

13. The gas supply revenues reflect the 2012 forecast of Gas Costs to Operations (at October 1, 2011 QRAM reference price) in the amount of $1,515.50 million including changes to the Company’s 2012 gas supply portfolio relative to the 2011 gas supply portfolio as well as storage and storage associated transportation costs. Changes to these elements are not captured through the Company’s QRAM rate changes. The 2012 gas supply portfolio includes the changes to transportation capacity for System Reliability. The cost consequences of these changes are not reflected in the 2012 rate adjustment but will take effect in the Company’s January 1, 2012 QRAM rates. This is consistent with the Company’s QRAM methodology which adjusts rates in each quarter of a fiscal year to reflect changes in commodity and upstream transportation costs.

14. The Company’s existing October 1, 2011 QRAM rates have a Purchased Gas Variance Account (“PGVA”) reference price of $196.778 10^3m^3. The PGVA reference price is comprised of commodity, transportation and load balancing costs. Applying the individual price elements underpinning this reference price to the

forecast gas supply mix for 2012 yields a PGVA reference price of $194.573 10^3m^3, which represents a decrease from the October 2011 QRAM level.

15. The development of the gas commodity, load balancing, and transportation unit rates is guided by the assignment of the revenue requirement for each of these elements. The complete development of these unit rates is shown at Exhibit B, Tab 3, Schedule 7 and the allocation of the gas supply revenue requirement is shown at Exhibit B, Tab 3, Schedule 10, page 4. Storage and unaccounted for gas (i.e., distribution commodity) costs are recovered through the Company's delivery charges.

16. Within the Company's Revenue Cap per Customer incentive regulation model, the assignment of the gas supply revenue requirement and the derivation of the gas commodity, load balancing, and transportation unit rates continue to be determined in the same manner as under the cost-of-service regime. This is facilitated by an annual forecast of Gas Costs to Operations and volumes budget. These forecasts provide a revenue requirement for each of the gas supply elements and enable an update to the allocators.

Rate Design: Distribution Revenues

17. The distribution revenues include a base 2012 distribution revenue requirement of $839.99 million, which is derived using the proposed Revenue Cap per Customer incentive regulation escalation formula, distribution revenue requirement of $167.30 million for the Y factors and Z factor distribution revenue requirement of $21.50 million.

18. The distribution revenue requirement is recovered in the Company's rates primarily from the delivery charges, however, some distribution-related costs are recovered from the commodity and load balancing charges.

19. The Company used allocators reflecting 2012 forecast to assign the test year distribution revenue requirement to the customer classes. By updating forecasts and allocators annually, the assignment of revenue requirement by rate class, and consequently rate impacts, remain responsive to factors such as customer growth, volumes gain or loss and customer migration between various rates and service offerings. The Y factor and Z factor revenue requirements were assigned to the customer classes based on specific drivers for that type of expenditure such as peak demand or customer numbers.

Rate Design: 2012 Proposed Rates

20. In the rate design process, consistent with the approach to design of rates in a cost of service environment, the Company used the assignment of the 2012 revenue requirement (Exhibit B, Tab 3, Schedule 10, pp. 1 - 9) as a guide to establish the proposed rates.

21. The Company has designed the proposed 2012 rates while balancing the following objectives: rate stability, continuity, rate class characteristics, and rate impacts for the various customer classes, market acceptance, avoidance of rate shock, and continuance of competitive position.

22. The Company also validated that there is an appropriate assignment of revenue responsibility among rate classes and that rates remain related to revenue requirement by measuring the proposed revenues to be recovered from each rate

class relative to the assignment of the test year revenue requirement. This validation is provided at Exhibit B, Tab 3, Schedule 10, pages 1 and 2.

Other

System Gas and DPAC Charges

23. Consistent with the 2011 Settlement Agreement (EB-2010-0146, Exhibit N1, Tab 1, Schedule, 1 p. 11) regarding the Direct Purchase Administration Charge ("DPAC") and the System Gas Administration Fee, the Company has retained the 2012 DPAC and System Gas fees at the 2010 level. For DPAC, the monthly fixed charge remains at $75 per pool, and the monthly account charge of $0.21 per account continues to apply. For the System Gas Fee, the unit rate of 0.0224 ¢/m^3 remains unchanged at the 2010 level.

Low-Income DSM

24. In its Demand Side Management Guidelines for Natural Gas Utilities issued on June 30, 2011, the Board provided a framework for natural gas utilities' multi-year DSM plans from 2012 – 2014. Section 8.3 of the Guidelines directed the utilities to recover funding for Low-Income DSM programs "from all rate classes, to be consistent with the electricity conservation and demand management framework, as well as the Low-Income Energy Assistance Program ("LEAP") Emergency Financial Assistance program" (p. 26) based on the Distribution Revenue Requirement ("DRR") per rate class.

25. The Company has allocated its 2012 Low-Income DSM costs to all rate classes in proportion to its 2011 DRR. Given the timing and consultative requirements of the DSM proceeding for the 2012 program year (EB-2011-0295), it was necessary to determine and provide an allocation of the Low Income budget prior to the

completion of the assignment of the 2012 DRR. Allocations of the 2012 DRR and the 2011 DRR are very similar. The Low-Income DSM budget allocation is provided at Exhibit B, Tab 3, Schedule 10, page 6 at Line 1.3.

Proposed Z Factors

26. As outlined at Exhibit B, Tab 1, Schedule 2, page 1, the Company is proposing new Z factors for 2012: (1) Pension funding requirement (Row 24), and (2) Cross bore/ Sewer Lateral program requirement (Row 25).

27. The Company proposes to allocate the Pension funding requirement proportionally to the allocation of the 2012 distribution revenue requirement (excluding proposed Z factors) for each rate class. The revenue requirement for the Cross bore/Sewer Lateral program is allocated on the services allocation factor. The allocations of the proposed Z Factor amounts to each rate class are found at Exhibit B, Tab 3, Schedule 10, page 6, at Lines 1.7 and 1.8.

Rate Handbook

28. Rate 200 is a wholesale service available to distributors outside EGD's franchise area who use EGD's distribution system to supply gas to their customers. The Company is proposing to change its Rate 200 (Wholesale Service) rate schedule, specifically, the provisions of interruptible service under Rate 200. The objective of the proposed changes is to make the wording uniform with EGD's interruptible service under Rate 145 and Rate 170 that was addressed in the OEB's System Reliability Decision (EB-2010-0231). The proposed changes are highlighted with bold and italic font in the Rate 200 rate schedule found under Exhibit B, Tab 3, Schedule 2, page 32.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

RATE HANDBOOK

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

INDEX

Part I

GLOSSARY OF TERMS

In this Handbook of Rates and Distribution Services, each term set out below shall have the meaning set out opposite it:

Annual Turnover Volume ("ATV"): The sum of the contracted volumes injected into and withdrawn from storage by an applicant within a contract year.

Annual Volume Deficiency: The difference between the Minimum Annual Volume and the volume actually taken in a contract year, if such volume is less than the Minimum Annual Volume.

Applicant: The party who makes application to the Company for one or more of the services of the Company and such term includes any party receiving one or more of the services of the Company.

Authorized Volume: In regards to Sales Service Agreements, the Contract Demand.

In regards to Bundled Transportation Service arrangements, the Contract Demand (CD) less the amount by which the Applicant's Mean Daily Volume (MDV) exceeds the Daily Delivered Volume (Delivery) and less the volume by which the Applicant has been ordered to curtail or discontinue the use of gas (Curtailment Volume) or otherwise represented as:

CD – (MDV – Delivery) – Curtailment Volume

Back-stopping: A service whereby alternative supplies of gas may be available in the event that an Applicant's supply of gas is not available for delivery to the Company.

Banked Gas Account: A record of the amount of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of volume of gas taken by the Applicant at the Terminal Location (debits)

Billing Contract Demand: Applicable only to new customers who take Dedicated Service under Rate 125. The Company and the Applicant shall determine a Billing Contract Demand which would result in annual revenues over the term of the contract that would enable the Company to recover the invested capital, return on capital, and O&M costs of the Dedicated Service in accordance with its system expansion policies.

Billing Month: A period of approximately thirty (30) days following which the Company renders a bill to an applicant. The billing month is determined by the Company's monthly Reading and Billing Schedule. With respect to rate 135 LVDC's, there are eight summer months and four winter months.

Board: Ontario Energy Board. (OEB)

Bundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Company utilizing Load balancing resources.

Buy/Sell Arrangement: An arrangement, the terms of which are provided for in one or more agreements to which one or more of an end user of gas (being a party that buys from the Company gas delivered to a Terminal Location), an affiliate of an end user and a marketer, broker or agent of an end user is a party and the Company is a party, and pursuant to which the Company agrees to buy from the end user or its affiliate a supply of gas and to sell to the end user gas delivered to a Terminal Location served from the gas distribution network. The Company will not enter into any new buy/sell agreement after April 1, 1999.

Buy/Sell Price: The Price per cubic meter which the Company would pay for gas purchased pursuant to a Buy/Sell Arrangement in which the purchase takes place in Ontario.

Commodity Charge: A charge per unit volume of gas actually taken by the Applicant, as distinguished from a demand charge which is based on the maximum daily volume an Applicant has the right to take.

Company: Enbridge Gas Distribution Inc.

Contract Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule for each Terminal Location which is the maximum volume of gas the Company is required to deliver on a daily basis under a Large Volume Distribution Contract.

Cubic Metre ("m^3"): That volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa") occupies one cubic metre. "10^3m^3" means 1,000 cubic metres.

Curtailment: An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

Curtailment Credit: A credit available to interruptible customers to recognize the benefits they provide to the system during the winter months.

Curtailment Delivered Supply (CDS): An additional volume of gas, in excess of the Applicant's Mean Daily Volume and determined by mutual agreement between the Applicant and the Company, which is Nominated and delivered by or on behalf of the Applicant to a point of interconnection with the Company's distribution system on a day of Curtailment.

Customer Charge: A monthly fixed charge that reflects being connected to the gas distribution system.

Daily Consumption VS Gas Quantity: The volume of natural gas taken on a day at a Terminal Location as measured by daily metering equipment or, where the Company does not own and maintain daily metering equipment at a Terminal Location, the volume of gas taken within a billing period divided by the number of days in the billing period.

Daily Delivered Volume: The volume of gas accepted by the Company as having been delivered by an Applicant to the Company on a day.

Dedicated Service: An Unbundled Service provided through a gas distribution pipeline that is initially constructed to serve a single customer, and for which the volume of gas is measured through a billing meter that is directly connected to a third party transporter or other third party facility, when service commences.

Delivery Charge: A component of the Rate Schedule through which the Company recovers its operating costs.

Demand Charge: A fixed monthly charge which is applied to the Contract Demand specified in a Service Contract.

Demand Overrun: The amount of gas taken at a Terminal Location exceeding the Contract Demand.

Direct Purchase: Natural gas supply purchase arrangements transacted directly between the Applicant and one or more parties, including the Company.

Disconnect and Reconnect Charges: The charges levied by the Company for disconnecting or reconnecting an Applicant from or to the Company's distribution system.

Diversion: Delivery of gas on a day to a delivery point different from the normal delivery point specified in a Service Contract.

Firm Service: A service for a continuous delivery of gas without curtailment, except under extraordinary circumstances.

Firm Transportation ("FT"): Firm Transportation service offered by upstream pipelines to move gas from a receipt point to a delivery point, as defined by the pipeline.

Force Majeure: Any cause not reasonably within the control of the Company and which the Company cannot prevent or overcome with reasonable due diligence, including:

(a) physical events such as an act of God, landslide, earthquake, storm or storm warning such as a hurricane which results in evacuation of an affected area, flood, washout, explosion, breakage or accident to machinery or equipment or lines of pipe used to transport gas, the necessity for making repairs to or alterations of such machinery or equipment or lines of pipe or inability to obtain materials, supplies (including a supply of services) or permits required by the Company to provide service;

(b) interruption and/or curtailment of firm transportation by a gas transporter for the Company;

(c) acts of others such as strike, lockout or other industrial disturbance, civil disturbance, blockade, act of a public enemy, terrorism, riot, sabotage, insurrections or war, as well as physical damage resulting from the negligence of others;

(d) in relation to Load Balancing, failure or malfunction of any storage equipment or facilities of the Company; and

(e) governmental actions, such as necessity for compliance with any applicable laws.

Gas: Natural Gas.

Gas Delivery Agreement: A written agreement pursuant to which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Gas Distribution Network: The physical facilities owned by the Company and utilized to contain, move and measure natural gas.

Gas Sale Contract: A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Gas Supply Charge: A charge for the gas commodity purchased by the applicant.

Gas Supply Load Balancing Charge: A charge in the Rate Schedules where the Company recovers the cost of ensuring gas supply matches consumption on a daily basis.

General Service Rates: The Rate Schedules applicable to those Bundled Services for which a specific contract between the Company and the Applicant is not generally required. The General Service Rates include Rates 1, 6, and 9 of the Company.

Gigajoule ("GJ"): See Joule.

Hourly Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule which is the maximum volume of gas the Company is required to deliver to an Applicant on a hourly basis under a Service Contract.

Imperial Conversion Factors:

Volume:		
1,000 cubic feet (cf)	=	1 Mcf
	=	28.32784 cubic metres (m^3)
1 billion cubic feet (cf)	=	28.32784 $10^6 m^3$
Pressure:		
1 pound force per square inch (p.s.i.)	=	6.894757 kilopascals (kPa)
1 inch Water Column (in W.C.) (60°F)	=	0.249 kPa (15.5°C)
1 standard atmosphere	=	101.325 kPa
Energy:		
1 million British thermal units	=	1 MMBtu
	=	1.055056 gigajoules (GJ)
948,213.3 Btu	=	1 GJ
Monetary Value:		
$1 per Mcf	=	$0.03530096 per m^3
$1 per MMBtu	=	$0.9482133 per GJ

Interruptible Service: Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the Company.

Intra-Alberta Service: Firm transportation service on the Nova pipeline system under which volumes are delivered to an Intra-Alberta point of acceptance.

Joule ("J"): The amount of work done when the point of application of a force of one newton is displaced a distance of one metre in the direction of the force. One megajoule ("MJ") means 1,000,000 joules; one gigajoule ("GJ") means 1,000,000,000 joules.

Large Volume Distribution Contract: (LVDC): A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Large Volume Distribution Contract Rates: The Rate Schedules applicable for annual consumption exceeding 340,000 cubic metres of gas per year and for which a specific contract between the Company and the Applicant is required.

Load-Balancing: The balancing of the gas supply to meet demand. Storage and other peak supply sources, curtailment of interruptible services, and diversions from one delivery point to another may be used by the Company.

Make-up Volume: A volume of gas nominated and delivered, pursuant to mutually agreed arrangements, by an Applicant to the Company for the purpose of reducing or eliminating a net debit balance in the Applicant's Banked Gas Account.

Mean Daily Volume (MDV): The volume of gas which an Applicant who delivers gas to the Company, under a T-Service arrangement, agrees to deliver to the Company each day in the term of the arrangement.

Metric Conversion Factors:

Volume:		
1 cubic metre (m^3)	=	35.30096 cubic feet (cf)
1,000 cubic metres	=	10^3m^3
	=	35,300.96 cf
	=	35.30096 Mcf
28.32784 m^3	=	1 Mcf
Pressure:		
1 kilopascal (kPa)	=	1,000 pascals
	=	0.145 pounds per square inch (p.s.i.)
101.325 kPa	=	one standard atmosphere
Energy:		
1 megajoule (MJ)	=	1,000,000 joules
	=	948.2133 British thermal units (Btu)
1 gigajoule (GJ)	=	948,213.3 Btu
1.055056 GJ	=	1 MMBtu
Monetary Value:		
\$1 per 10^3m^3	=	\$0.02832784 per Mcf
\$1 per gigajoule	=	\$1.055056 per MMBtu

Minimum Annual Volume: The minimum annual volume as stated in the customer's contract, also Section E.

Natural Gas: Natural and/or residue gas comprised primarily of methane.

Nominated Volume: The volume of gas which an Applicant has advised the Company it will deliver to the Company in a day.

Nominate, Nomination: The procedure of advising the Company of the volume which the Applicant expects to deliver to the Company in a day.

Ontario Energy Board: An agency of the Ontario Government which, amongst other things, approves the Company's Rate Schedules (Part V of this HANDBOOK) and the matters described in Parts III and IV of this HANDBOOK.

Point of Acceptance: The point at which the Company accepts delivery of a supply of natural gas for transportation to, or purchase from, the Applicant.

Rate Schedule: A numbered rate of the Company as fixed or approved by the OEB. that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

Seasonal Credit: A credit applicable to Rate 135 customers to recognize the benefits they provide to the storage operations during the winter period.

Service Contract: An agreement between the Company and the Applicant which describes the responsibilities of each party in respect to the arrangements for the Company to provide Sales Service or Transportation Service to one or more Terminal Locations.

System Sales Service: A service of the Company in which the Company acquires and sells to the Applicant the Applicant's natural gas requirements.

T-Service: Transportation Service.

Terminal Location: The building or other facility of the Applicant at or in which natural gas will be used by the Applicant.

Transportation Service: A service in which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Unbundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Applicant contracting for separate services (upstream transportation, load balancing/storage, transportation on the Company's distribution system) of which only Transportation Service is mandatory with the Company.

Western Canada Buy Price: The price per cubic metre which the Company would pay for gas pursuant to a Buy/Sell Agreement in which the purchase takes place in Western Canada.

PART II

RATES AND SERVICES AVAILABLE

The provisions of this PART II are intended to provide a general description of services offered by the Company and certain matters relating thereto. Such provisions are not definitive or comprehensive as to their subject matter and may be changed by the Company at any time without notice.

SECTION A - INTRODUCTION

1. In Franchise Services

Enbridge Gas Distribution provides in franchise services for the transportation of natural gas from the point of its delivery to Enbridge Gas Distribution to the Terminal Location at which the gas will be used. The natural gas to be transported may be owned by the Applicant for service or by the Company. In the latter case, it will be sold to the customer at the outlet of the meter located at the Terminal Location.

Applicants may elect to have the Company provide all-inclusively the services which are mutually agreed to be required or they may select (from the 300 series of rates, and Rate 125) only the amounts of those services which they consider they need.

The all-inclusive services are provided pursuant to Rates 1, 6 and 9, ("the General Service Rates") and Rates 100, 110, 115, 135, 145, and 170 ("the Large Volume Service Rates"). Individual services are available under Rates 125, 300, 315, and 316 ("the Unbundled Service Rates").

Service to residential locations is provided pursuant to Rate 1.

Service which may be interrupted at the option of the Company is available, at rates lower than would apply for equivalent service under a firm rate schedule, pursuant to Rates 145, 170. Under all other rate schedules, service is provided upon demand by the Applicant, i.e., on a firm service basis.

2. Ex-Franchise Services

Enbridge Gas Distribution provides ex-franchise services for the transportation of natural gas through its distribution system to a point of interconnection with the distribution system of other distributors of natural gas. Such service is provided pursuant to Rate 200 and provides for the bundled transportation of gas owned by the Company, owned by customers of that distributor, or owned by that distributor.

For the purposes of interpreting the terms and conditions contained in this Handbook of Rates and Distribution Services the ex - franchise distributor shall be considered to be the applicant for the transportation of its customer owned gas and shall assume all the obligations of transportation as if it owned the gas.

Nominations for transportation service must specify whether the volume to be transported is to displace firm or interruptible demand or general service.

In addition, the Company provides Compression, Storage, and Transmission services on its Tecumseh system under Rates 325, 330 and 331.

SECTION B - DIRECT PURCHASE ARRANGEMENTS

Applicants who purchase their natural gas requirements directly from someone other than the Company or who are brokers or agents for an end user, may arrange to transport gas on the Company's distribution network in conjunction with a Western Buy/Sell Arrangement or pursuant to an Ontario Delivery Transportation Service Arrangement, whether Bundled or Unbundled, or a Western Bundled Transportation Service Arrangement.

B. Western Canada

Buy/Sell in a Western Canada Buy/Sell Arrangement the Applicant delivers gas to a point in Western Canada which connects with the transmission pipeline of TransCanada PipeLines Limited. At that point, the Company purchases the gas from the Applicant at a price specified in Rider 'B' of the rate schedules less the costs for transmission of the gas from the point of purchase to a point in Ontario at which the Company's gas distribution network connects with a transmission pipeline system. The Company will not be entering into any new Western Canada buy/sell arrangements after April 1, 1999.

C. Ontario Delivery T-Service Arrangements

In an Ontario Delivery T-Service Arrangement the Applicant delivers gas, to a contractually agreed-upon point of acceptance in Ontario.

Delivery from the point of direct interconnection with the Company's gas distribution network to a Terminal Location served from the Company's gas distribution network may be obtained by the Applicant either under the Bundled Service Rate Schedules or under the Unbundled Service Rate Schedules.

(i) Bundled T-Service

Bundled T-Service is so called because all of the services required by the Applicant (delivery and load balancing) are provided for the prices specified in the applicable Rate Schedule. In a Bundled T-Service arrangement the Applicant contracts to deliver each day to the Company a Mean Daily Volume of gas. Fluctuations in the demand for gas at the Terminal Location are balanced by the Company.

(ii) Unbundled T-Service

The Unbundled Service Rates allow an Applicant to contract for only such kinds of service as the Applicant chooses. The potential advantage to an Applicant is that the chosen amounts of service may be less than the amounts required by an average customer represented in the applicable Rate Schedule, in which case the Applicant may be able to reduce the costs otherwise payable under Bundled T-Service.

D. Western Delivery T-Service Arrangement

In a Western Delivery T-Service Arrangement the Applicant contracts to deliver each day to a point on the TransCanada PipeLines Ltd. transmission system in Western Canada a Mean Daily Volume of gas plus fuel gas. Delivery from that point to the Terminal Location is carried out by the Company using its contracted capacity on the TransCanada PipeLines Limited. system and its gas distribution network. Unbundled T-Service in Ontario is not available with the Western Delivery Option.

An Applicant desiring to receive Transportation Service or to establish a Buy/Sell Agreement must first enter into the applicable written agreements with the Company.

PART III

TERMS AND CONDITIONS APPLICABLE TO ALL SERVICES

The provisions of this PART III are applicable to, and only to, Sales Service and Transportation Service.

SECTION A - AVAILABILITY

Unless otherwise stated in a Rate Schedule, the Company's rates and services are available throughout the entire franchised area serviced by the Company. Transportation service and/or sales service will be provided subject to the Company having the capacity in its gas distribution network to provide the service requested. When the Company is requested to supply the natural gas to be delivered, service shall be available subject to the Company having available to it a supply of gas adequate to meet the requirement without jeopardizing the supply to its existing customers.

Service shall be made available after acceptance by the Company of an application for service to a Terminal Location at which the natural gas will be used.

SECTION B - ENERGY CONTENT

The price of natural gas sold at a Terminal Location is based on the assumption that each cubic metre of such natural gas contains a certain number of megajoules of energy which number is specified in the Rate Schedules. Variations in cost resulting from the energy content of the gas actually delivered to the Company by its supplier(s) differing from the assumed energy content will be recorded and used to adjust future bills. Such adjustments shall be made in accordance with practices approved from time to time by the Ontario Energy Board.

SECTION C - SUBSTITUTION PROVISION

The Company may deliver gas from any standby equipment provided that the gas so delivered shall be reasonably equivalent to the natural gas normally delivered.

SECTION D - BILLS

Bills will be mailed or delivered monthly or at such other time period as set out in the Service Contract. Gas consumption to which the Company's rates apply will be determined by the Company either by meter reading or by the Company's estimate of consumption where meter reading has not occurred. The rates and charges applicable to a billing month shall be those applicable to the calendar month which includes the last day of the billing month.

SECTION E - MINIMUM BILLS

The minimum bill per month applicable to service under any particular Rate Schedule shall be the Customer Charge plus any applicable Contract Demand Charges for Delivery, Gas Supply Load Balancing, and Gas Supply and any applicable Direct Purchase Administration Charge, all as provided for in the applicable Rate Schedule.

In addition, for service under each of the Large Volume Distribution Contact Rates, if in a contract year a volume of gas equal to or greater than the product of the Contract Demand multiplied by a contractually specified multiple of the Contract Demand ("Minimum Annual Volume") is not taken at the Terminal Location the Applicant shall pay, in addition to the minimum monthly bills, the amount obtained when the difference between the Minimum Annual Volume and the volume taken in the contract year (such difference being the Annual Volume Deficiency) is multiplied by the applicable Minimum Bill Charge(s) as provided for in the applicable Rate Schedule. Notwithstanding the foregoing, the Minimum Annual Volume shall be the greater of the Minimum Annual Volume as determined above and 340,000 m^3.

If gas deliveries to the Terminal Location have been ordered to be curtailed or discontinued in a contract year at the request of the Company and have been curtailed or discontinued as ordered, the Minimum Annual Volume shall be reduced for each day of curtailment or discontinuance by the excess of the Contract Demand over the volume delivered to the Terminal Location on such day.

SECTION F - PAYMENT CONDITIONS

Enbridge Gas Distribution charges are due when the bill is received, which is considered to be three days after the date the bill is rendered, or within such other time period as set out in the Service Contract. A late payment charge of 1.5% per month (19.56% effectively per annum) of all of the unpaid Enbridge Gas Distribution charges, including all applicable federal and provincial taxes, is applied to the account on the seventeenth (17th) day following the date the bill is due.

SECTION G - TERM OF ARRANGEMENT

When gas service is provided and there is no written agreement in effect relating to the provision of such service, the term for which such service is to continue shall be one year. The term shall automatically be extended for a further year immediately following the expiry of any initial one year term or one year extension unless reasonable notice to terminate service is given to the Company, in a manner acceptable to the Company, prior to the expiry of the term. An Applicant receiving such service who temporarily discontinues service in the initial one year term or any one year extension and does not pay all the minimum bills for the period of such temporary discontinuance of service shall, upon the continuance of service, be liable to pay an amount equal to the unpaid minimum bills for such period. When a written agreement is in effect relating to the provision of gas service, the term for which such service is to continue shall be as provided for in the agreement.

SECTION H - RESALE PROHIBITION

Gas taken at a Terminal Location shall not be resold other than in accordance with all applicable laws and regulations and orders of any governmental authority or OEB having jurisdiction.

SECTION I - MEASUREMENT

The Company will install, operate and maintain at a Terminal Location such measurement equipment of suitable capacity and design as is required to measure the volume of gas delivered. Any special conditions for measurement are contained in the General Terms and Conditions which form part of each Large Volume Distribution Contract.

SECTION J - RATES IN CONTRACTS

Notwithstanding any rates for service specified in any Service Contract, the rates and charges provided for in an applicable Rate Schedule shall apply for service rendered on and after the effective date stated in such Rate Schedule until such Rate Schedule ceases to be applicable.

SECTION K - ADVICE RE: CURTAILMENT

The Company, if requested, will advise Applicants taking interruptible service of its estimate of service curtailment for the forthcoming winter. Such estimate will be provided as guidance to the Applicant in arranging for alternate fuel supply requirements. Abnormal weather and/or other unforeseen events may cause greater or lesser curtailment of service than expected.

SECTION L - DAILY DELIVERED VOLUMES

For purposes including that of calculating daily overrun gas volumes, the Company will recognize as having been delivered to it on a given day the sum of:

a) the volume of gas delivered under Intra-Alberta transportation arrangements, if any, plus;

b) the volume of gas delivered under FT transportation arrangements, if any, plus;

SECTION M - AUTHORIZED OVERRUN GAS

If an Applicant requests permission to exceed the Authorized Volume for a day, and such authorization is granted, such gas shall constitute Authorized Overrun Gas. Such gas shall either be sold by the Company to the Applicant pursuant to the provisions of Rate 320 applicable on such day, or, at the Company's sole discretion, under the Rate Schedule the customer is purchasing prior to such request. If the Applicant is supplying their own gas requirements and if the Applicant request and at the Company's sole discretion, such Overrun Gas will be debited to the Applicant's Banked gas Account.

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

If an Applicant for Transportation Service pursuant to the General Service Rates on any day delivers to the Company a Daily Delivered Volume which is less than the Mean Daily Volume, the volume of gas by which the Mean Daily Volume applicable to such day exceeds the Daily Delivered Volume delivered by the Applicant to the Company on such day shall constitute Unauthorized Supply Overrun Gas and shall be deemed to have been taken and purchased on such day. The rate applicable to such volume shall be 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and the EDA delivery areas respectively.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under the Large Volume Distribution Contract Rates is:

(a) the volume of gas by which the Daily Gas Quantity under the Service Contract on such day exceeds the Authorized Volume for such day, if any

plus

(b) if the day is in the months of December to March inclusive for an Applicant taking service on Rate 135 under Option a) or if the day is in the month of December under Option b), or if the day is a day on or in respect of which the Applicant has been requested in accordance with the Service Contract to curtail or discontinue the use of gas and the Service Contract is in whole or in part for interruptible Transportation Service, the volume of gas, if any, by which

(i) the Mean Daily Volume set out in the Service Contract and is applicable to such day exceeds

(ii) the Daily Delivered Volume delivered by the Applicant to the Company on such day, which excess volume of gas shall be deemed to have been taken and purchased by the Applicant on such day.

The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

An Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate must provide two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean Daily Volume for a specified time period. Failure to provide proper notice will result in Unauthorized Supply Overrun Gas calculated as the difference between Daily Delivered Volume and the Mean Daily Volume.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under Rate 125 or Rate 300 shall be determined from the provisions of the applicable Rate Schedule. The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

SECTION O – COMPANY RESPONSIBILTY AND LIABILITY

This Section O applies only to gas distribution service under Rates 1, 6 and 9, and does not replace or supercede the terms in any applicable Service Contract.
The Company shall make reasonable efforts to maintain, but does not guarantee, continuity of gas service to its customers. The Company may, in its sole discretion, terminate or interrupt gas service to customers;

to maintain safety and reliability on, or to facilitate construction, installation, maintenance, repair, replacement or inspection of the Company's facilities; or

for any reason related to dangerous or hazardous circumstances, emergencies or Force Majeure.

The Company shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind, whether direct, indirect, special or consequential in nature, (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising from or connected with any failure, defect, fluctuation or interruption in the provision of gas service by the Company to its customers.

PART IV

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

Any Applicant, at the time of applying for service, may elect, in and for the term of any Service Contract, to deliver its own natural gas requirements to the Company and the Company shall deliver gas to a Terminal Location as required by the Applicant, subject to the terms and conditions contained in the applicable Rate Schedule and in the Service Contract. For Buy/Sell Arrangements and Bundled T-Service the deliveries by the Applicant to the Company shall be at the Applicant's estimated mean daily rate of consumption.

Backstopping of an Applicant's natural gas supply for Transportation Service arrangements will be available pursuant to Rate 320 subject to the Company's ability to do so using reasonable commercial efforts. Gas Purchase Agreements in respect to Buy/Sell Arrangements shall specify terms and conditions available to the Company to alleviate certain consequences of the Applicant's failure to deliver the required volume of gas.

The following Terms and Conditions shall apply to, and only to, Transportation Service and/or Gas Purchase Agreements.

SECTION A - NOMINATIONS

An Applicant delivering gas to the Company pursuant to a contract is responsible for advising the Company, by means of a contractually specified Nomination procedure, of the daily volume of gas to be delivered to the Company by or on behalf of the Applicant.

An initial daily volume must be Nominated by a contractually specified time before the first day on which gas is to be delivered to the Company. Any Nomination, once accepted by the Company, shall be considered as a standing nomination applicable to each subsequent day in a contract term unless specifically varied by written notice to the Company.

A contract may specify certain contractual provisions that are applicable in the event that an Applicant either fails to advise of a revised daily nomination or fails to deliver the daily volume so nominated.

A Nominated Volume in excess of the Applicant's Maximum Daily Volume as specified in the Service Contract will not be accepted except as specifically provided for in any contract.

SECTION B - OBLIGATION TO DELIVER

During any period of curtailment or discontinuance of Bundled interruptible Transportation Service as ordered by the Company, any Applicant supplying its own gas requirements must, on such day, deliver to the Company the Mean Daily Volume of gas specified in any Service Contract.

Each Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate is obligated to deliver the Mean Daily Volume of gas as specified in any Service Contract, unless the Applicant provides two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean daily Volume for a specified time period.

An Applicant taking service on Rate 135 under Option a) must deliver to the Company the Mean Daily Volume of gas specified in the Service Contract in the months of December to March, inclusive.

An Applicant taking service on Rate 135 under Option b) must deliver to the Company the Modified Mean Daily Volume of gas specified in the Service Contract in the month of December.

Applicants taking service on General Service rates pursuant to a Direct Purchase Agreement must, on each day in the term of such agreement, deliver to the Company the Mean Daily Volume of gas specified in such agreement.

SECTION C - DIVERSION RIGHTS

Subject to compliance with the Terms and Conditions of all Required Orders, an Applicant who has entered into a Transportation Service Agreement or Agreements which provide(s) for deliveries to the Company for more than one Terminal Location shall have the right, on such terms and only on such terms as are specified in the applicable Transportation Service Agreement, to divert deliveries from one or more contractually specified Terminal Locations to other contractually specified Terminal Locations.

SECTION D - BANKED GAS ACCOUNT (BGA)

For T-Service Applicants, the Company shall keep a record ("Banked Gas Account") of the volume of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of the volume of gas taken by the Applicant at the Terminal Location (debits). (Any volume of gas sold by the Company to the Applicant in respect to the Terminal Location shall not be debited to the Banked Gas Account). The Company shall periodically report to the Applicant the net balance in the Applicant's Banked Gas Account.

SECTION E - DISPOSITION OF BANKED GAS ACCOUNT (BGA) BALANCES

A. The following Terms and Conditions shall apply to Bundled T-Service:

(a) At the end of each contract year, disposition of any net debit balance in the Banked Gas Account (BGA) shall be made as follows:

The Applicant, by written notice to the Company within thirty (30) days of the end of the contract year, may elect to return to the Company, in kind, during the one hundred and eighty (180) days following the end of the contract year, that portion of any debit balance in the Banked Gas Account as at the end of the contract year not exceeding a volume of twenty times the Applicant's Mean Daily Volume by the Applicant delivering to the Company on days agreed upon by the Company and the Applicant a volume of gas greater than the Mean Daily Volume, if any, applicable to such day under a Service Contract. Any volume of gas returned to the Company as aforesaid shall not be credited to the Banked Gas Account in the subsequent contract year. Any debit balance in the Banked Gas Account as at the end of the contract year which is not both elected to be returned, and actually returned, to the Company as aforesaid shall be deemed to have been sold to the Applicant and the Applicant shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be:

(1) for *Bundled Western T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

(2) for *Bundled Ontario T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, plus the Company's average transportation cost to its franchise area over the contract year.

(b) A credit balance in the Banked Gas Account as at the end of the contract year must be eliminated in one or more of the following manners, namely:

(i) Subject to clause (ii), if the Applicant continues to take service from the Company under a contract pursuant to which the Applicant delivers gas to the Company and the Applicant so elects (by written notice to the Company within thirty (30) days of the end of the contract year), that portion of such balance which the Applicant stipulates in such written notice and which does not exceed twenty times the Applicant's Mean Daily Volume may be carried forward as a credit to the Banked Gas Account for the next succeeding contract year. Any volume duly elected to be carried forward under this clause shall, and may only, be reduced within the period of one hundred and eighty (180) days ("Adjustment Period") immediately following the contract year, by the Applicant delivering to the Company, on days in the Adjustment Period agreed upon by the Company and the Applicant ("Adjustment Days"), a volume of gas less than the Mean Daily Volume applicable to such day under a Service Contract. Subject to the foregoing, the credit balance in the Banked Gas Account shall be deemed to be reduced on each Adjustment Day by the volume ("Daily Reduction Volume") by which the Mean Daily Volume applicable to such day exceeds the greater of the volume of gas delivered by the Applicant on such day and the Nominated Volume for such day which was accepted by the Company.

(ii) Any portion of a credit balance in the Banked Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to the Company within thirty (30) days of the end of the contract year) to sell under this clause, shall be deemed to have been tendered for sale to the Company and the Company shall purchase such portion at:

(1) for *Bundled Western T*-Service, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the Company's average transportation cost to its franchise area over the contract year.

(2) for *Bundled Ontario T-Service*, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

Any volume of gas deemed to have been so tendered for sale shall be deemed to have been eliminated from the credit balance of the Banked Gas Account.

During the Adjustment Period the Company shall use reasonable efforts to accept the Applicant's reduced gas deliveries. Any credit balance in the Banked Gas Account not eliminated as aforesaid in the Adjustment Period shall be forfeited to, and be the property of, the Company, and such volume of gas shall be debited to the Banked Gas Account as at the end of the Adjustment Period.

Subject to its ability to do so, the Company will attempt to accommodate arrangements which would permit adjustments to Banked Gas Account balances at times and in a manner which are mutually agreed upon by the Applicant and the Company.

B. The following Terms and Conditions shall apply to Unbundled Service:

The Terms and Conditions for disposition of Cumulative Imbalance Account balances shall be as specified in the applicable Service Contracts.

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a residential building served through one meter and containing no more than six dwelling units ("Terminal Location").

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$20.00**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**8.3758 ¢/m³**
For the next 55 m³ per month	**7.8919 ¢/m³**
For the next 85 m³ per month	**7.5128 ¢/m³**
For all over 170 m³ per month	**7.2305 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.6558 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider “F”.
The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") for non-residential purposes.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month
	January to December
Monthly Customer Charge	**$70.00**
Delivery Charge per cubic metre	
For the first 500 m³ per month	**7.8679 ¢/m³**
For the next 1050 m³ per month	**6.1912 ¢/m³**
For the next 4500 m³ per month	**5.0173 ¢/m³**
For the next 7000 m³ per month	**4.2628 ¢/m³**
For the next 15250 m³ per month	**3.9276 ¢/m³**
For all over 28300 m³ per month	**3.8437 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.7031 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider “F”.
The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

RATE NUMBER: 9	CONTAINER SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") at which, such gas is authorized by the Company to be resold by filling pressurized containers.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$242.18**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**11.0422 ¢/m³**
For all over 20,000 m³ per month	**10.3360 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5585 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified annual volume of natural gas of not less than 340,000 cubic metres to be delivered at a specified maximum daily rate.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$126.67**
Delivery Charge	
Per cubic metre of Contract Demand	**8.1900 ¢/m³**
For the first 14,000 m³ per month	**5.2427 ¢/m³**
For the next 28,000 m³ per month	**3.8837 ¢/m³**
For all over 42,000 m³ per month	**3.3247 ¢/m³**
Gas Supply Load Balancing Charge	**0.4882 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5608 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **11.3762 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

RATE NUMBER: 110	LARGE VOLUME LOAD FACTOR SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 183 times a specified maximum daily volume of not less than 1,865 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$609.82**
Delivery Charge	
Per cubic metre of Contract Demand	**22.9100 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.6659 ¢/m³**
For all over 1,000,000 m³ per month	**0.5159 ¢/m³**
Gas Supply Load Balancing Charge	**0.1353 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5585 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: 110

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

6.4464 ¢/m³

In determining the Annual Volume Deficiency, the minimum bill multiplier shall not be less than 183.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

RATE NUMBER: **115**	**LARGE VOLUME LOAD FACTOR SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 292 times a specified maximum daily volume of not less than 1,165 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month
	January to December
Monthly Customer Charge	**$622.62**
Delivery Charge	
Per cubic metre of Contract Demand	**24.3600 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.2667 ¢/m³**
For all over 1,000,000 m³ per month	**0.1667 ¢/m³**
Gas Supply Load Balancing Charge	**0.0507 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5585 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

5.9627 ¢/m³

In determining the Annual Volume Deficiency the minimum bill multiplier shall not be less than 292.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified maximum daily volume of natural gas. The maximum daily volume for billing purposes, Contract Demand or Billing Contract Demand, as applicable, shall not be less than 600,000 cubic metres. The Service under this rate requires Automatic Meter Reading (AMR) capability.

CHARACTER OF SERVICE:

Service shall be firm except for events specified in the Service Contract including force majeure.

For Non-Dedicated Service the monthly demand charges payable shall be based on the Contract Demand which shall be 24 times the Hourly Demand and the Applicant shall not exceed the Hourly Demand.

For Dedicated Service the monthly demand charges payable shall be based on the Billing Contract Demand or the Contract Demand specified in the Service Contract. The Applicant shall not exceed an hourly flow calculated as 1/24th of the Contract Demand specified in the Service Contract.

DISTRIBUTION RATES:

The following rates and charges, as applicable, shall apply for deliveries to the Terminal Location.

Monthly Customer Charge	**$500.00**
Demand Charge	
Per cubic metre of the Contract Demand or the Billing Contract Demand, as applicable, per month	**9.2092 ¢/m³**
Direct Purchase Administration Charge	**$75.00**
Forecast Unaccounted For Gas Percentage	**0.3%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a). In the case of a Dedicated Service, the Unaccounted for Gas volume requirement is not applicable.

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG. Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 125 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

   Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA) or other Delivery Area as specified in the applicable Service Contract. The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed the Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 125 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

The Company permits pooling of Rate 125 contracts for legally related customers who meet the Business Corporations Act (Ontario) ("OBCA") definition of "affiliates" to allow for the management of those contracts by a single manager. The single manager is jointly liable with the individual customers for all of their obligations under the contracts, while the individual customers are severally liable for all of their obligations under their own contracts.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery (the sum of the customer’s Contract Demand and the authorized overrun amount) required to serve the customer’s daily load, plus the UFG. In the event that gas usage exceeds the gas delivery on a day where demand overrun is authorized, the excess gas consumption shall be deemed Supply Overrun Gas.
Such service shall not exceed 5 days in any contract year. Based on the terms of the Service Contract, requests beyond 5 days will constitute a request for a new Contract Demand level with retroactive charges. The new Contract Demand level may be restricted by the capability of the local distribution facilities to accommodate higher demand.

Automatic authorization of transportation overrun over the Billing Contract Demand will be given in the case of Dedicated Service to the Terminal Location provided that pipeline capacity is available and subject to the Contract Demand as specified in the Service Contract.

Authorized Demand Overrun Rate	**0.30 ¢/m³**

The Authorized Demand Overrun Rate may be applied to commissioning volumes at the Company's sole discretion, for a contractual period of not more than one year, as specified in the Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas may establish a new Contract Demand effective immediately and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Based on capability of the local distribution facilities to accommodate higher demand, different conditions may apply as specified in the applicable Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below***.**

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following day's Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule, including the load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location or at the location of the meter installation for a customer served from a dedicated facility. In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources including where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed the Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA), or other Delivery Area as specified in the applicable Service Contract.

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's Terminal Location or in the event of combined nominations at the Terminal Locations specified.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance:

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery since the date the customer last balanced or was deemed to have balanced its Cumulative Imbalance account.

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand for non dedicated service and 60% of the Billing Contract Demand for dedicated service.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = 0.7497 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 0.8996 cents/m3 applied to Daily Imbalance of greater than 10% but less than the Maximum Contractual Imbalance

In addition for Tier 2, instances where the Daily Imbalance represents an under delivery of gas during the winter season shall constitute Unauthorized Supply Overrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. Where the Daily Imbalance represents an over delivery of gas during the summer season, the Company reserves the right to deem as Unauthorized Supply Underrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. The Company will issue a 24-hour advance notice to customers of its intent to impose cash out for over delivery of gas during the summer season.

For customers delivering to a Primary Delivery Area other than EGD's CDA or EGD's EDA, the Tier 1 Fee is applied to Daily Imbalance of greater than 0% but less than 10% of the Maximum Contractual Imbalance

The customers shall also pay any Limited Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rates 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances. The Company will provide the customer with a derivation of any such charges.

Customer’s Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer’s Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area. Customers may also nominate to transfer gas from their Cumulative Imbalance Account into an unbundled (Rate 315 or Rate 316) storage account of the customer subject to their storage contract parameters.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed the Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds the Contract Demand.

The customer’s Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. In the event that the customer's imbalance exceeds their Maximum Contractual Imbalance the Company shall deem the excess imbalance to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee, applicable daily, is 1.0618 cents/m3 per unit of imbalance.

In addition, on any day that the Company declares an Operational Flow Order, negative Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance in the winter season shall be deemed to be Unauthorized Overrun Gas. The Company reserves the right to deem positive Cumulative Imbalances greater than 10% of Maximum Contractual Imbalance in the summer season as Unauthorized Supply Underun Gas. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders including cash out instructions for Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 340,000 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure. A maximum of five percent of the contracted annual volume may be taken by the Applicant in a single month during the months of December to March inclusively.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month	
	December to March	**April to November**
Monthly Customer Charge	**$119.24**	**$119.24**
Delivery Charge		
For the first 14,000 m³ per month	**6.8162 ¢/m³**	**2.1162 ¢/m³**
For the next 28,000 m³ per month	**5.6162 ¢/m³**	**1.4162 ¢/m³**
For all over 42,000 m³ per month	**5.2162 ¢/m³**	**1.2162 ¢/m³**
Gas Supply Load Balancing Charge	**0.0000 ¢/m³**	**0.0000 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.6345 ¢/m³**	**13.6345 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

The applicant has the option of delivering either Option a) a Mean Daily Volume ("MDV") based on 12 months, or Option b) a Modified Mean Daily Volume ("MMDV") based on nine months of deliveries. Authorized Volumes for the months of January, February and March would be zero under option b).

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Failure to deliver a volume of gas equal to the Mean Daily Volume under Option a) set out in the Service Contract during the months of December to March inclusive may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

Failure to deliver a volume of gas equal to the Modified Mean Daily Volume under Option b) set out in the Service Contract during the month of December may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

SEASONAL CREDIT:

Rate per cubic metre of Mean Daily Volume from December to March	**$**	**0.77 /m³**
Rate per cubic metre of Modified Mean Daily Volume for December	**$**	**0.77 /m³**

SEASONAL OVERRUN CHARGE:

During the months of December through March inclusively, any volume of gas taken in a single month in excess of five percent of the annual contract volume (Seasonal Overrun Monthly Volume) will be subject to Seasonal Overrun Charges in place of both the Delivery and Gas Supply Load Balancing Charges. The Seasonal Overrun Charge applicable for the months of December and March shall be calculated as 2.0 times the sum of the Gas Supply Load Balancing Charge, Transportation Charge and the maximum Delivery Charge. The Seasonal Overrun Charge applicable for the months of January and February shall be calculated as 5.0 times the sum of the Load Balancing Charge, Transportation Charge and the maximum Delivery Charge.

Seasonal Overrun Charges:

December and March	**25.0048 ¢/m³**
January and February	**62.5120 ¢/m³**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **9.3281 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

RATE NUMBER: 145	INTERRUPTIBLE SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service as ordered by the Company exercising its sole discretion. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source. Any Applicant for service under this rate schedule must agree to transport a minimum annual volume of 340,000 cubic metres.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 16 hours prior to the time at which such curtailment or discontinuance is to commence. An Applicant may, by contract, agree to accept a shorter notice period.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$127.99**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.8881 ¢/m³**
For the next 28,000 m³ per month	**1.5291 ¢/m³**
For all over 42,000 m³ per month	**0.9701 ¢/m³**
Gas Supply Load Balancing Charge	**0.2104 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.7246 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 16 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 0.50 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**8.7437 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas of not less than 30,000 cubic metres and a minimum annual volume of 5,000,000 cubic metres to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service when required by the Company. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source.
The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$289.58**
Delivery Charge	
Per cubic metre of Contract Demand	**4.0900 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5474 ¢/m³**
For all over 1,000,000 m³ per month	**0.3474 ¢/m³**
Gas Supply Load Balancing Charge	**0.1194 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5585 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**6.3120 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Distributor who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of an annual supply of natural gas to customers outside of the Company's franchise area.

CHARACTER OF SERVICE:

Service shall be continuous (firm), except for events as specified in the Service Contract including force majeure, up to the contracted firm daily demand and subject to curtailment or discontinuance, of demand in excess of the firm contract demand, upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	
The monthly customer charge shall be negotiated with the applicant and shall not exceed:	**$2,000.00**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**14.7000 ¢/m³**
Per cubic metre of gas delivered	**1.2581 ¢/m³**
Gas Supply Load Balancing Charge	**0.5684 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5585 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**13.5361 ¢/m³**

The rates quoted above shall be subject to the Gas Inventory Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable to volumes of natural gas purchased from the Company. The volumes purchased shall be the volumes delivered at the Point of Delivery less any volumes, which the Company does not own and are received at the Point of Acceptance for delivery to the Applicant at the Point of Delivery.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to receive interruptible service under this rate schedule.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

~~**The third instance of such failure in any contract year may result in the Applicant orfeiting the right to be served under this Rate Schedule. In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.**~~

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**7.4717 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation to a single Terminal Location of a specified maximum daily volume of natural gas. The Company reserves the right to limit service under this schedule to customers whose maximum contract demand does not exceed 600,000 m3. The Service under this rate requires Automatic Meter Reading (AMR) capability. Service under this schedule is firm unless a customer is currently served under interruptible distribution service or the Company, in its sole judgment, determines that existing delivery facilities cannot adequately serve the load on a firm basis.

The unitized Monthly Contract Demand Charge is also applicable to volumes delivered to any Applicant taking service under a Curtailment Delivered Supply contract with the Company. The unitized rate equals the applicable Monthly Contract Demand Charge times 12/365.

CHARACTER OF SERVICE:

The Service shall be continuous (firm) except for events specified in the Service Contract including force majeure. The Applicant is neither allowed to take a daily quantity of gas greater than the Contract Demand nor an hourly amount in excess of the Contract Demand divided by 24, without the Company's prior consent. Interruptible Distribution Service is provided on a best efforts basis subject to the events identified in the service contract including force majeure and, in addition, shall be subject to curtailment or discontinuance of service when the Company notifies the customer under normal circumstances 4 hours prior to the time that service is subject to curtailment or discontinuance. Under emergency conditions, the Company may curtail or discontinue service on one-hour notice. The Interruptible Service Customer is not allowed to exceed maximum hourly flow requirements as specified in Service Contract.

DISTRIBUTION RATES:

Monthly Customer Charge	**$500.00**
Monthly Contract Demand Charge Firm	**25.2824 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3633 ¢/m³**
Maximum Delivery Charge	**0.9974 ¢/m³**
Direct Purchase Administration Charge	**$75.00**
Forecast Unaccounted For Gas Percentage	**0.3%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Contract Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a).

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG, net of No-Notice Storage Service provisions under Rate 315, if applicable. The amount of gas delivered under No-Notice Storage Service will also be reduced by the UFG adjustment factor for delivery to the customer's meter.

   Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 300 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA) *or* other Delivery Area as specified in the applicable Service Contract. The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 300 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery required to serve the customer's daily load, including quantities of gas in excess of the Contract Demand, plus the UFG. The Load Balancing Provisions and/or No-Notice Storage Service provisions under Rate 315 cannot be used for Authorized Demand Overrun. Failure to nominate gas deliveries to match Authorized Demand Overrun shall constitute Unauthorized Supply Overrun.

The rate applicable to Authorized Demand Overrun shall equal the applicable Monthly Demand Charge times 12/365 provided, however, that such service shall not exceed 5 days in any contract year. Requests beyond 5 days will constitute a request for a new Contract Demand level, with retroactive charges based on terms of Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas will establish a new Contract Demand and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions. Where a customer receives interruptible service hereunder and consumes gas during a period of interruption, such gas shall be deemed Unauthorized Supply Overrun. In addition to charges for Unauthorized Supply Overrun, interruptible customers consuming gas during a scheduled interruption shall pay a penalty charge of $18.00 per m3.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below*.

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable Rate 300 Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following days Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule, including interruptible service and load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

Load Balancing:

Any difference between actual daily-metered consumption and the actual daily volume of gas delivered to the system less the UFG shall first be provided under the provisions of Rate 315 - Gas Storage Service, if applicable. Any remaining difference will be subject to the Load Balancing Provisions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location.

In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources plus, where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA), or other Delivery Area as specified in the applicable Service Contract.

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's premise.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance:

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery.

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance and shall be subject to a charge of 0.7497 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 0.8996 cents/m3

The customers shall also pay any Limited Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rate 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances.

A Daily Imbalance in excess of the Maximum Contractual Imbalance shall be deemed to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

Customer's Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer's Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds Contract Demand.

The customer's Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. The excess imbalance shall be deemed to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee, applicable daily, is 0.684 cents/m3 per unit of imbalance.

The customer's Cumulative Imbalance shall be equal to zero within five (5) days from the last day of the Service Contract.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

APPLICABILITY:

This rate is available to any customer taking service under Distribution Rates 125 and 300. It requires a Service Contract that identifies the required storage space and deliverability. In addition, the customer shall maintain a positive balance of gas in storage at all times or forfeit the use of Storage Services for Load Balancing and No-Notice Storage Service.

A daily nomination for storage injection and withdrawal except for No-Notice Storage Service, hereunder, which is used automatically for daily Load Balancing, shall also be required.

The maximum hourly injections / withdrawals shall equal $1/24^{th}$ of the daily Storage Demand. No-Notice Storage Service is available up to the maximum daily withdrawal rights less the nominated withdrawal or the maximum daily injection rights less the nominated injections.

Storage space shall be based on either of two storage allocation methodologies: (customer's average winter demand - customer's average annual demand) x 151, or [(17 x customers's maximum hourly demand) / 0.1] x 0.57. Customers have the option to select from these two storage space allocation methods the one that best suits their requirements.

Maximum deliverability shall be 1.2% of contracted storage space. The customer may inject and withdraw gas based on the quantity of gas in storage and the limitations specified in the Service Contract. Both injection and withdrawal shall be subject to applicable storage ratchets as determined by the Company and posted from time to time.

CHARACTER OF SERVICE:

Service shall be firm when used in conjunction with firm distribution service. Service is interruptible when used in conjunction with interruptible distribution service. All service is subject to contract terms and force majeure.

The service is available on two bases:

(1) Service nominated daily based on the available capacity and gas in storage up to the maximum contracted daily deliverability; and

(2) No-Notice Storage Service for daily Load Balancing consistent with the maximum hourly deliverability.

RATE:

The following rates and charges shall apply in respect to all gas received by the Company from and delivered by the Company to storage on behalf of the Applicant.

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0567 ¢/m³**
Monthly Storage Deliverability Demand Charge	**16.1123 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.3383 ¢/m³**

Monthly Minimum Bill: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations and No-Notice Storage Service quantities.

All deemed withdrawal quantities under the No-Notice Storage Service provisions of this rate will be adjusted for the UFG provisions applicable to the distribution service rates.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

TERMS AND CONDITIONS OF SERVICE:

1. **Nominated Storage Service**:

Nominations under this rate shall only be accepted at the standard North American Energy Standards Board ("NAESB") nomination windows. The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to the applicable Primary Delivery Area, which may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA). All volumes nominated from storage are delivered first for purposes of daily Load Balancing of available supply assets. When system conditions permit, the customer may nominate all or a portion of the available withdrawal capacity for delivery to Dawn or to the customer's Primary Delivery Area for purposes other than consumption at the customer's own meter.

Storage not nominated for delivery will be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's Contract Demand (CD).

The customer may also nominate gas for delivery into storage by nominating the storage delivery area as the Primary Delivery Area. Gas nominated for storage delivery will not be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's CD.
Any gas in excess of the contract demand will be subject to cash out as injection overrun gas.

The Company reserves the right to limit injection and withdrawal rights to all storage customers in certain situations, such as major maintenance or construction projects, and may reduce nominations for injections and withdrawals over and above applicable storage ratchets. The Company will provide customers with one week's notice of its intent to limit injection and withdrawal rights, and at the same time, shall provide its best estimate of the duration and extent of the limitations.

In situations where the Company limits injection and withdrawal rights, the Company shall proportionately reduce the Storage Deliverability/Injection Demand Charge for affected customers based on the number of days the limitation is in effect and the difference between Deliverability/Injection Demand, subject to applicable storage ratchets, and the quantity of gas actually delivered or injected.

2. **No-Notice Storage Service**:

The Company, at its sole discretion based on operating conditions, may provide a No-Notice Storage Service that allows customers taking gas under distribution service rates to balance daily deliveries using this Storage Service. No-Notice Storage Service requires that the customer grant the Company the exclusive right to use unscheduled service available from storage to reduce the daily imbalance associated with the actual consumption of the customer.

No-Notice Storage Service is limited to the available, unscheduled withdrawal or injection capacity under contract to serve a customer. Where the customer serves multiple delivery locations from a single storage Service Contract, the customer shall specify the order in which gas is to be delivered to each Terminal Location served under a distribution Service Contract. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location.

The availability of No-Notice Storage Service is subject to and reduced by any service schedule from or to storage. To the extent that the quantity of gas available in storage is insufficient to meet the requirements of the customer under a No-Notice Storage Service, the customer will be unable to use the service on a no-notice basis for Load Balancing service. To the extent that the scheduled injections into storage plus No-Notice Storage Service exceed the maximum limit for injection, No-Notice Storage Service will be reduced and the remainder of the gas will constitute a daily imbalance. Gas delivered in excess of the maximum injection quantity shall be deemed injection overrun gas and cashed out at 50% of the lowest index price of gas.

Other provisions:

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its own gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

APPLICABILITY:

This rate is available to any customer taking service under Distribution Rates 125 and 300. It requires a Service Contract that identifies the required storage space and deliverability. The customer shall maintain a positive balance of gas in storage at all times. In addition, the customer must arrange for pipeline delivery service from Dawn to the applicable Primary Delivery Area.

This service is not a delivered service and is only available when the relevant pipeline confirms the delivery.

The maximum hourly injections / withdrawals shall equal $1/24^{th}$ of the daily Storage Demand.

Storage space shall be based on either of two storage allocation methodologies: (customer's average winter demand - customer's average annual demand) x 151, or [(17 x customers's maximum hourly demand) / 0.1] x 0.57. Customers have the option to select from these two storage space allocation methods the one that best suits their requirements.

Maximum deliverability shall be 1.2% of contracted storage space. The customer may inject and withdraw gas based on the quantity of gas in storage and the limitations specified in the Service Contract. Both injection and withdrawal shall be subject to applicable storage ratchets as determined by the Company and posted from time to time.

CHARACTER OF SERVICE:

Service shall be firm when used in conjunction with firm distribution service. Service is interruptible when used in conjunction with interruptible distribution service. All service is subject to contract terms and force majeure.

The service is nominated based on the available capacity and gas in storage up to the maximum contracted daily deliverability.

RATE:

The following rates and charges shall apply in respect to all gas received by the Company from and delivered by the Company to storage on behalf of the Applicant.

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0567 ¢/m³**
Monthly Storage Deliverability Demand Charge	**5.1445 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.1049 ¢/m³**

Monthly Minimum Bill: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

TERMS AND CONDITIONS OF SERVICE:

Nominated Storage Service:

The customer shall nominate storage injections and withdrawals daily. The customer may change daily nominations based on the nomination windows within a day as defined by the customer contract with Union Gas Limited and TransCanada PipeLines (TCPL).

The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to the applicable Primary Delivery Area.

The Company reserves the right to limit injection and withdrawal rights to all storage customers in certain situations, such as major maintenance or construction projects, and may reduce nominations for injections and withdrawals over and above applicable storage ratchets. The Company will provide customers with one week's notice of its intent to limit injection and withdrawal rights, and at the same time, shall provide its best estimate of the duration and extent of the limitations.

In situations where the Company limits injection and withdrawal rights, the Company shall proportionately reduce the Storage Deliverability/Injection Demand Charge for affected customers based on the number of days the limitation is in effect and the difference between Deliverability/Injection Demand, subject to applicable storage ratchets, and the quantity of gas actually delivered or injected.

The customer may transfer the title of gas in storage.

Other provisions:

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its own gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

RATE NUMBER: **320**	**BACKSTOPPING SERVICE**

APPLICABILITY:

To any Applicant whose delivery of natural gas to the Company for transportation to a Terminal Location has been interrupted prior to the delivery of such gas to the Company.

CHARACTER OF SERVICE:

The volume of gas available for backstopping in any day shall be determined by the Company exercising its sole discretion. If the aggregate daily demand for service under this Rate Schedule exceeds the supply available for such day, the available supply shall be allocated to firm service customers on a first requested basis and any balance shall be available to interruptible customers on a first requested basis.

RATE:

The rates applicable in the circumstances contemplated by this Rate Schedule, in lieu of the Gas Supply Charges specified in any of the Company's other Rate Schedules pursuant to which the Applicant is taking service, shall be as follows:

	Billing Month
	January to December
Gas Supply Charge	
Per cubic metre of gas sold	**19.7114 ¢/m³**

provided that if upon the request of an Applicant, the Company quotes a rate to apply to gas which is delivered to the Applicant at a particular Terminal Location on a particular day or days and to which this Rate Schedule is applicable (which rate shall not be less than the Company's avoided cost in the circumstances at the time nor greater than the otherwise applicable rate specified above), then the Gas Supply Charge applicable to such gas shall be the rate quoted by the Company.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY AND CHARACTER OF SERVICE:

Service under this rate schedule shall apply to the Transmission and Compression Service Agreement with Union Gas Limited dated April 1, 1989, and the Transmission, Compression and Pool Storage Service Agreement with Centra Gas Ontario Inc. dated May 30, 1994. Service shall be provided subject to the terms and conditions specified in the Service Agreement.

RATE:

The Customer shall pay for service rendered in each month in a contract year, the sum of the following applicable charges:

	Transmission & Compression $\$/10^3m^3$	Pool Storage $\$/10^3m^3$
Demand Charge for:		
Annual Turnover Volume	**0.1916**	**0.2273**
Maximum Daily Withdrawal Volume	**17.3202**	**20.6179**
Commodity Charge	**0.9654**	**0.3242**

FUEL RATIO REQUIREMENT:

Fuel Ratio applicable to per unit of gas injected and withdrawn is 0.35%.

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges as stated in Rate Section above.

EXCESS VOLUME AND OVERRUN RATES:

In addition to the charges provided for in the Rate Section above, the Customer shall pay, for services rendered, the sum of the following applicable charges as they are incurred:

TERMS AND CONDITIONS OF SERVICE:

1. Excess Volumes will be billed at the total of the Excess Volume Charges as stated above.

2. Transmission and Compression, and Pool Storage Overrun Service will be billed according to the following:
   (a) At the end of each month, in a contract year, the Company will make a determination, for each day in the month, of

      (i) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account into the Company System, at the Point of Delivery and the Customer's Maximum Daily Injection Volume, and

      (ii) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account from the Company System, at the Point of Delivery, and the Customer's Maximum Daily Withdrawal Volume.

	Excess Volume Charge $/10³m³ / Year	Overrun Charge $/10³m³ / Day
Transmission & Compression		
Authorized	**2.5288**	**0.5694**
Unauthorized	**-**	**228.6263**
Pool Storage		
Authorized	**3.0004**	**0.6778**
Unauthorized	**-**	**272.1560**

(b) For each day of the month, where any such differences exceed 2.0 percent of the Customer's relevant Maximum Daily Injection Volume and/or Maximum Daily Withdrawal Volume, the Customer shall pay a charge equal to the relevant Overrun rates, as stated above, for such differences.

BILLING ADJUSTMENT:

1. Injection deficiency - If at the beginning of any Withdrawal Period the Customer's Storage Balance is less than the Customer's Annual Turnover Volume, due solely to the Company's inability to inject gas for any reason other than the fault of the Customer, then the applicable Demand Charge for Annual Turnover Volume for the contract year beginning the prior April 1 as stated in Rate Section as applicable, shall be adjusted by multiplying each by a fraction, the numerator of which shall be the Customer's Storage Gas Balance as of the beginning of such Withdrawal Period and the denominator shall be the Customer's Annual Turnover Volume as it may have been established for the then current year.

2. Withdrawal deficiency - If in any month in a contract year for any reason other than the fault of the Customer, the Company fails or is unable to deliver during any one or more days, the amount of gas which the Customer has nominated, up to the maximum volumes which the Company is obligated by the Agreement to deliver to the Customer, then the Demand Charge for maximum Contract Daily Withdrawal Volume in the contract year otherwise payable for the month in which such failure occurs, as stated in Rate Section above, as applicable, shall be reduced by an amount for each day of deficiency to be calculated as follows: The Demand Charge for maximum Contract Daily Withdrawal Volume for the contract year for the month will be divided by 30.4 and the result obtained will then be multiplied by a fraction, the numerator being the difference between the nominated volume for such day and the delivered volume for such day and the denominator being the Customer's maximum Contract Daily Withdrawal Volume for such contract year.

TERMS AND EXPRESSIONS:

In the application of this Rate Schedule to each of the Agreements, terms and expressions used in this Rate Schedule have the meanings ascribed thereto in such Agreement.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

TRANSMISSION AND COMPRESSION AND POOL STORAGE

APPLICABILITY:

To any Applicant who enters into a Storage Contract with the Company for delivery by the Applicant to the Company and re-delivery by the Company to the Applicant of a volume of natural gas owned by the Applicant.

CHARACTER OF SERVICE:

Service under this rate is for Full Cycle or Short Cycle storage service; with firm or interruptible injection and withdrawal service, all as may be available from time to time.

RATE:

The following rates and charges shall apply in respect of all gas received by the Company from and re-delivered by the Company to the Applicant.

	Full Cycle		Short Cycle
	Firm	Interruptible	
	$\$/10^3m^3$	$\$/10^3m^3$	$\$/10^3m^3$
Monthly Demand Charge per unit of Annual Turnover Volume:			
Minimum	**0.4189**	**0.4189**	**-**
Maximum	**2.0945**	**2.0945**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**37.9381**	**30.3505**	**-**
Maximum	**189.6905**	**151.7524**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**1.2896**	**1.2896**	**0.6771**
Maximum	**6.4480**	**6.4480**	**38.9530**

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

TRANSACTING IN ENERGY:

The conversion factor is 37.74MJ/m3, which corresponds to Union Gas' System Wide Average Heating Value, as per the Board's RP-1999-0017 Decision with Reasons.

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges.

RATE NUMBER: **330**

OVERRUN RATES:

The units rates stated below will apply to overrun volumes. The provision of Authorized Overrun service will be at the Company's sole discretion.

	Full Cycle Firm $\$/10^3m^3$	Full Cycle Interruptible $\$/10^3m^3$	Short Cycle $\$/10^3m^3$
Authorized Overrun Annual Turnover Volume Negotiable, not to exceed:	**38.9530**	**38.9530**	**38.9530**
Authorized Overrun Daily Injection/Withdrawal Negotiable, not to exceed:	**38.9530**	**38.9530**	**38.9530**
Unauthorized Overrun Annual Turnover Volume Excess Storage Balance			
September 1 - November 30	**389.5305**	**389.5305**	**389.5305**
December 1 - October 31	**38.9530**	**38.9530**	**38.9530**
Unauthorized Overrun Annual Turnover Volume Negative Storage Balance			

TERMS AND CONDITIONS OF SERVICE:

1. All Services are available at the Company's sole discretion.

2. Delivery and Re-delivery of the volume of natural gas shall be from/to the facilities of Union Gas Limited and / or TransCanada PipeLines Limited in Dawn Township and/or Niagara Gas Transmission Limited in Moore Township.

3. The Customers daily injections or withdrawals will be adjusted to provide for the fuel ratio stated in the Fuel Ratio Section. In the event that a Short Cycle service does not require fuel for injection and/or withdrawal, the fuel ratio commodity charge may be waived.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

RATE NUMBER: **331**	**TECUMSEH TRANSPORTATION SERVICE**

APPLICABILITY:

To any Applicant who enters into an agreement with the Company pursuant to the Rate 331 Tariff (“Tariff”) for transportation service on the Company’s pipelines extending from Tecumseh to Dawn (“Tecumseh Pipeline”). The Company will receive gas at Tecumseh and deliver the gas at Dawn. Capitalized terms used in this Rate Schedule shall have the meanings ascribed to those terms in the Tariff.

CHARACTER OF SERVICE:

Transportation service under this Rate Schedule may be available on a firm basis (“FT Service”) or an interruptible basis (“IT Service”), subject to the terms and conditions of service set out in the Tariff and the applicable rates set out below.

RATE:

The following rates, effective January 1, 2012, shall apply in respect of FT and IT Service under this Rate Schedule:

	Demand Rate $\$/10^3m^3$	Commodity Rate $\$/10^3m^3$
FT Service	**5.3030**	**-**
IT Service	**-**	**0.2090**

FT Service: The monthly demand charge shall be the products obtained by multiplying the applicable Maximum Daily Volume by the above demand rate.

IT Service: The monthly commodity charge shall be the product obtained by multiplying the applicable Delivery Volume for the Month by the above commodity rate.

TERMS AND CONDITIONS OF SERVICE:

The terms and conditions of FT and IT Service are set out in the Tariff. The provisions of PARTS I to IV of the Company's HANDBOOK OF RATES AND DISTRIBUTION SERVICES do not apply to Rate 331 service.

EFFECTIVE DATE:

The Tariff was approved by the Board in Board Order EB-2010-0177, dated July 12, 2010, and is posted and available on the Company's website. In accordance with Section 1.6.2 of the Board's Storage and Transportation Access Rule, the Tariff does not apply to any Rate 331 service agreements executed prior to June 16, 2010.

Applicants located off the piping networks noted below or off piping systems supplied from these networks may be curtailed to maintain distribution system integrity.

The Town of Collingwood
The Town of Midland

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Transportation Agreement with the Company under any rate other than Rates 125 and 300.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00	per month
Account Charge	$0.21	per month per account

AVERAGE COST OF TRANSPORTATION:

The average cost of transportation effective January 1, 2012:

Point of Acceptance	Firm Transportation (FT)
CDA, EDA	5.6862 ¢/m³

<u>TCPL FT CAPACITY TURNBACK:</u>

APPLICABILITY:

To Ontario T-Service and Western T-Service customers who have been or will be assigned TCPL capacity by the Company.

TERMS AND CONDITIONS OF SERVICE:

1. The Company will accommodate TCPL FT capacity turnback requests from customers, but only if it can do so in accordance with the following considerations:
   i. The FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to the TCPL FT capacity;
   ii. The amount of turnback capacity that Enbridge otherwise may accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs resulting from the loss of STS capacity arising from any turnback request; and
   iii. Enbridge must act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.
2. Requests for TCPL FT turnback must be made in writing to the attention of Enbridge's Direct Purchase group.
3. All TCPL FT capacity turnback requests will be treated on an equitable basis.
4. The percentage turnback of TCPL FT capacity will be applied at the Direct Purchase Agreement level.

5. Written notice to turnback capacity must be received by the Company the earlier of:

   (a) Sixty days prior to the expiry date of the current contract.

   or

   (b) A minimum of one week prior to the deadline specified in TransCanada tariff for FT contract extension.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

APPLICABILITY:

This rider is applicable to any Applicant who entered into a Gas Purchase Agreement with the Company, prior to April 1, 1999, to sell to the Company a supply of natural gas.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00	per month
Account Charge	$0.21	per month per account

BUY / SELL PRICE:

In Buy/Sell Arrangements between the Company and an Applicant, the Company shall buy the Applicants gas at the Company's actual FT-WACOG price determined on a monthly basis in the manner approved by the Ontario Energy Board. For Western Buy/Sell arrangements the FT-WACOG price shall be reduced by pipeline transmission costs.

FT FUEL PRICE:

The FT fuel price used to establish the Buy price in Western Buy/Sell arrangements without fuel will be determined monthly based upon the actual FT-WACOG.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

RIDER: C	GAS COST ADJUSTMENT RIDER

The following adjustment is applicable to all gas sold or delivered during the period of January 1, 2012 to .

Rate Class	Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 1			
Rate 6			
Rate 9			
Rate 100			
Rate 110			
Rate 115			
Rate 135			
Rate 145			
Rate 170			
Rate 200			

RIDER: **C**

Rate Class		Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 1	Commodity			
	Transportation			
	Load Balancing			
	Total			
Rate 6	Commodity			
	Transportation			
	Load Balancing			
	Total			
Rate 9	Commodity			
	Transportation			
	Load Balancing			
	Total			
Rate 100	Commodity			
	Transportation			
	Load Balancing			
	Total			
Rate 110	Commodity			
	Transportation			
	Load Balancing			
	Total			
Rate 115	Commodity			
	Transportation			
	Load Balancing			
	Total			
Rate 135	Commodity			
	Transportation			
	Load Balancing			
	Total			

Rate Class		Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 145	Commodity			
	Transportation			
	Load Balancing			
	Total			
Rate 170	Commodity			
	Transportation			
	Load Balancing			
	Total			
Rate 200	Commodity			
	Transportation			
	Load Balancing			
	Total			

REVENUE ADJUSTMENT RIDER

Bundled Services Rate Class	Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 1	0.0000	0.0000	0.0000
Rate 6	0.0000	0.0000	0.0000
Rate 9	0.0000	0.0000	0.0000
Rate 100	0.0000	0.0000	0.0000
Rate 110	0.0000	0.0000	0.0000
Rate 115	0.0000	0.0000	0.0000
Rate 135	0.0000	0.0000	0.0000
Rate 145	0.0000	0.0000	0.0000
Rate 170	0.0000	0.0000	0.0000
Rate 200	0.0000	0.0000	0.0000

Unbundled Services Rate Class	Distribution Service (¢/m³)
Rate 125	0.0000
Rate 300	0.0000

RIDER: F	ATMOSPHERIC PRESSURE FACTORS

The following elevation factors shall be applicable to metered volumes measured by a meter that does not correct for atmospheric pressure.

Zone	Elevation Factor
1	0.9644
2	0.9652
3	0.9669
4	0.9678
5	0.9686
6	0.9703
7	0.9728
8	0.9745
9	0.9762
10	0.9771
11	0.9839
12	0.9847
13	0.9856
14	0.9864
15	0.9873
16	0.9881
17	0.9890
18	0.9898
19	0.9907
20	0.9915
21	0.9932
22	0.9941
23	0.9949
24	0.9958
25	0.9960
26	0.9966
27	0.9975
28	0.9981
29	0.9983
30	0.9992
31	0.9997
32	1.0000
33	1.0017
34	1.0025
35	1.0034
36	1.0051
37	1.0059
38	1.0170

	Rate (excluding GST)
New Account Or Activation	
New Account Charge Turning on of gas, activating appliances, obtaining billing data and establishing an opening meter reading for new customers in premises where gas has been previously supplied	$25.00
Appliance Activation Charge - Commercial Customers Only Commercial customers are charged an appliance activation charge on unlock and red unlock orders, except on the very first unlock and service unlock at a premise.	$70.00 minimum 1/2 hour work. Total Amount depends on time required
Meter Unlock Charge - Seasonal or Pool Heater Seasonal for all other revenue classes, or Pool Heater for residential only	$70.00
Statement of Account	
Lawyer Letter Handling Charge Provide the customer's lawyer with gas bill information.	$15.00
Statement of Account Charge (for one year history)	$10.00
Cheques Returned Non-Negotiable Charge	$20.00
Gas Termination	
Red Lock Charge Locking meter or shutting off service by closing the street shut-off valve (when work can be performed by Field Collector)	$70.00
Removal of Meter Removing meter by Construction & Maintenance crew	$280.00
Cut Off At Main Charge Cutting service off at main by Construction & Maintenance Crew	$1,300.00
Valve Lock Charge Shutting off service by closing the street	
shut-off valve - work performed by Field Investigator	$135.00
- work performed by Construction & Maintenance	$280.00

Safety Inspection	
Inspection Charge For inspection of gas appliances; the Company provides only one inspection free of charge, upon first time introduction of gas to a premise.	$70.00
Inspection Reject Charge (safety inspection) Energy Board Inspection rejects are billed to the meter installer or homeowner.	$70.00
Meter Test	
Meter Test Charge When a customer disputes the reading on his/her meter, he/she may request to have the meter tested. This charge will apply if the test result confirms the meter is recording consumption correctly.	
Residential meters	$105.00
Non-Residential meters	Time & Material per Contractor
Street Service Alteration	
Street Service Alteration Charge For installation of service line beyond allowable guidelines (for new residential services only)	$32.00
NGV Rental	
NGV Rental Cylinder (weighted average)	$12.00
Other Customer Services (ad-hoc request)	
Labour Hourly Charge-Out Rate	$140.00
Cut Off At Main Charge - Commercial & Special Requests Cut Off At Main charges for commercial services and other residential services that involve significantly more work than the average will be custom quoted.	custom quoted
Cut Off At Main Charge - Other Customer Requests Other residential Cut Off At Main requests due to demolitions, fires, inactive services, etc. will be charged at the standard COAM rate.	$1,300.00
Meter In-Out (Residential Only)) Relocate the meter from inside to outside per customer request	$280.00
Request For Service Call Information Provide written information of the result of a service call as requested by home owners.	$30.00
Temporary Meter Removal As requested by customers.	$280.00
Damage Meter Charge	$380.00

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Delivery Agreement with the Company under any rate.

IN FRANCHISE TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, an Applicant may elect to initiate a transfer of natural gas from one of its pools to the pool of another Applicant for the purposes of reducing an imbalance between the Applicant's deliveries and consumption as recorded in its Banked Gas Account or Cumulative Imbalance Account. Elections must be made in accordance with the Company's policies and procedures related to transaction requests under the Gas Delivery Agreement.

The Company will not apply an Administration charge for transfers between pools that have similar Points of Acceptance (i.e. both Ontario or both Western Points of Acceptance). For transfers between pools that have dissimilar Points of Acceptance (i.e. one an Ontario and one a Western Point of Acceptance), the Company will apply the following Administration Charge per transaction to the Applicant transferring the natural gas (i.e. the seller or transferor).

Administration Charge:	$169.00	per transaction

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to an Applicant with an Ontario Point of Acceptance. The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from an Applicant with an Ontario Point of Acceptance.

ENHANCED TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, the Applicant may elect to initiate a transfer of natural gas between the Company and another utility, regulated by the Ontario Energy Board, at Dawn for the purposes of reducing an imbalance between the customer's deliveries and consumption within the Enbridge Gas Distribution franchise areas. The ability of the Company to accept such an election may be constrained at various points in time for customers obtaining services under any rate other than Rate 125 or 300 due to operational considerations of the Company.

The cost for this service is separated between an Adminstration Charge that is applicable to all Applicants and a Bundled Service Charge that is only applicable to Applicants obtaining services under any rate other than Rate 125 or 300.

Administration Charge:		
Base Charge	$50.00	per transaction
Commodity Charge	$0.6448	per 10^3m^3

Bundled Service Charge:
The Bundled Service Charge shall be equal to the absolute difference between the Eastern Zone and Southwest Zone Firm Transportation tolls approved by the National Energy Board for TCPL at a 100% Load Factor.

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to another party. The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from another party.

RIDER:	H

GAS IN STORAGE TITLE TRANSFER:

An Applicant that holds a contract for storage services under Rate 315 or 316 may elect to initiate a transfer of title to the natural gas currently held in storage between the storage service and another storage service held by the Applicant, or any other Applicant that has contracted with the Company for storage services under Rate 315 or 316. The service will be provided on a firm basis up to the volume of gas that is equivalent to the more restrictive firm withdrawal and injection parameters of the two parties involved in the transfer. Transfer of title at rates above this level may be done on at the Company's discretion.

For Applicants requesting service between two storage service contracts that have like services, each party to the request shall pay an Administration Charge applicable to the request. Services shall be considered to be alike if the injection and deliverability rate at the ratchet levels in effect at the time of the request are the same and both services are firm or both services are interruptible. In addition to like services, the Company, at its sole discretion based on operational conditions, will also allow for the transfer of gas from a storage service contract that has a level of deliverability that is higher than the level of deliverability of the storage service contract the gas is being transfered to with only the Administration Charge being applicable to each party.

In addition to the Administration Charge, Applicants requesting service between two storage service contracts not addressed in the preceding paragraph would be subject to the injection and withdrawal charges specified in their contracts.

Administration Charge:	$25.00	per transaction

REVENUE REQUIREMENT - PROPOSED METHODOLOGY BY RATE CLASS AND COMPONENT ($000)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		REVENUE -EB-2011-0277 RATES				
ITEM NO.	RATE NO.	DISTRIBUTION	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL
1.	1	745,566	227,622	39,665	504,337	1,517,190
2.	6	334,366	191,613	35,767	359,101	920,847
3.	9	155	58	0	139	352
4.	100	0	0	0	0	0
5.	110	11,100	9,101	660	8,714	29,575
6.	115	6,461	569	270	0	7,301
7.	125	9,805	0	0	0	9,805
8.	135	954	1,233	(465)	84	1,805
9.	145	3,487	2,409	(521)	2,932	8,307
10.	170	4,528	3,254	(5,647)	6,736	8,870
11.	200	4,043	7,014	726	16,725	28,508
12.	300	385	0	0	0	385
13.	SUB-TOTAL	1,120,850	442,874	70,454	898,767	2,532,946
14.	STORAGE	1,619	0	0	0	1,619
15.	DPAC	2,212	0	0	0	2,212
16.	TOTAL	1,124,681	442,874	70,454	898,767	2,536,777

Witnesses: J. Collier
A. Kacicnik

PROPOSED VOLUMES AND REVENUE RECOVERY BY RATE CLASS ($000)

		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
		DISTRIBUTION			GAS SUPPLY TRANSPORTATION			GAS SUPPLY LOAD BALANCING			GAS SUPPLY COMMODITY			TOTAL
ITEM NO.	RATE NO.	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	REVENUES
		10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	$000
1.	1	4,583,338	745,566	16.27	4,003,100	227,622	5.69	4,583,338	39,665	0.87	3,693,205	504,337	13.66	1,517,190
2.	6	4,772,169	334,366	7.01	3,369,817	191,613	5.69	4,772,169	35,767	0.75	2,620,584	359,101	13.70	920,847
3.	9	1,177	155	13.13	1,027	58	5.69	1,177	0	0.00	1,027	139	13.56	352
4.	100	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0
5.	110	488,031	11,100	2.27	160,062	9,101	5.69	488,031	660	0.14	64,267	8,714	13.56	29,575
6.	115	532,453	6,461	1.21	10,015	569	5.69	532,453	270	0.05	0	0	0.00	7,301
7.	125	0	9,805	0.00	0	0	0.00	0	0	0.00	0	0	0.00	9,805
8.	135	55,183	954	1.73	21,679	1,233	5.69	55,183	(465)	(0.84)	613	84	13.63	1,805
9.	145	154,354	3,487	2.26	42,372	2,409	5.69	154,354	(521)	(0.34)	21,365	2,932	13.72	8,307
10.	170	519,974	4,528	0.87	57,218	3,254	5.69	519,974	(5,647)	(1.09)	49,679	6,736	13.56	8,870
11.	200	162,216	4,043	2.49	123,354	7,014	5.69	162,216	726	0.45	123,354	16,725	13.56	28,508
12.	300	31,049	385	0.00	0	0	0.00	0	0	0.00	0	0	0.00	385
13	SUB-TOTAL	11,299,945	1,120,850	9.92	7,788,644	442,874	5.6862	11,268,896	70,454	0.63	6,574,095	898,767	13.67	2,532,946
14.	STORAGE	N/A	1,619	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,619
15.	DPAC	N/A	2,212	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	2,212
16.	TOTAL	11,299,945	1,124,681	9.92	7,788,644	442,874	5.69	11,268,896	70,454	0.63	6,574,095	898,767	13.67	2,536,777

Witnesses: J. Collier
A. Kacicnik

REVENUE - PROPOSED METHODOLOGY BY RATE CLASS

	Col. 1	Col. 2	Col. 3	Col. 4
		REVENUE -EB-2011-0277 RATES		
Item No.	Rate No.	Proposed Revenue ($000)	Unbilled Revenue ($000)	Total ($000)
1.	1	1,517,190	1,971	1,519,162
2.	6	920,847	5,033	925,880
3.	9	352	0	352
4.	100	0	0	0
5.	110	29,575	232	29,807
6.	115	7,301	18	7,319
7.	125	9,805	0	9,805
8.	135	1,805	2	1,807
9.	145	8,307	172	8,479
10.	170	8,870	84	8,955
11.	200	28,508	0	28,508
12.	300	385	0	385
13.	SUB-TOTAL	2,532,946	7,512	2,540,458
14.	STORAGE	1,619	0	1,619
15.	DPAC	2,212	0	2,212
16.	TOTAL	2,536,777	7,512	2,544,289

Witnesses: J. Collier
A. Kacicnik

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

Item No.	Rate No.	Col. 1	Col. 2 Rate Block m³	Col. 3 EB-2011-0296 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2011-0277 cents *
	RATE 1					
1.01		Customer Charge		$19.00	$1.00	$20.00
1.02		Delivery Charge	first 30	7.3312	0.1792	7.5104
1.03			next 55	6.8589	0.1676	7.0265
1.04			next 85	6.4889	0.1586	6.6474
1.05			over 170	6.2133	0.1518	6.3651
1.06		Gas Supply Load Balancing		0.9566	(0.0911)	0.8654
1.07		Gas Supply Transportation		5.7181	(0.0319)	5.6862
1.08		Gas Supply Commodity - System		13.6891	(0.0333)	13.6558
1.09		Gas Supply Commodity - Buy/Sell		13.6668	(0.0334)	13.6334
	RATE 6					
2.01		Customer Charge		$65.00	$5.00	$70.00
2.02		Delivery Charge	First 500	7.0056	0.1129	7.1184
2.03			Next 1050	5.3554	0.0863	5.4417
2.04			Next 4500	4.2001	0.0677	4.2678
2.05			Next 7000	3.4576	0.0557	3.5133
2.06			Next 15250	3.1277	0.0504	3.1781
2.07			Over 28300	3.0451	0.0491	3.0942
2.08		Gas Supply Load Balancing		0.8574	(0.1079)	0.7495
2.09		Gas Supply Transportation		5.7181	(0.0319)	5.6862
2.10		Gas Supply Commodity - System		13.7537	(0.0506)	13.7031
2.11		Gas Supply Commodity - Buy/Sell		13.7313	(0.0506)	13.6807
	RATE 9					
3.01		Customer Charge		$235.89	$6.29	$242.18
3.02		Delivery Charge	first 20000	10.7695	0.2689	11.0385
3.03			over 20000	10.0805	0.2517	10.3323
3.04		Gas Supply Load Balancing		0.0040	(0.0003)	0.0037
3.05		Gas Supply Transportation		5.7181	(0.0319)	5.6862
3.06		Gas Supply Commodity - System		13.5786	(0.0201)	13.5585
3.07		Gas Supply Commodity - Buy/Sell		13.5562	(0.0201)	13.5361
	RATE 100					
4.01		Customer Charge		$122.01	$4.66	$126.67
4.02		Demand Charge (Cents/Month/m³)		8.1900	0.0000	8.1900
4.03		Delivery Charge	first 14,000	5.1222	0.1206	5.2427
4.04			next 28,000	3.7632	0.1206	3.8837
4.05			over 42,000	3.2042	0.1206	3.3247
4.06		Gas Supply Load Balancing		0.5908	(0.1079)	0.4882
4.07		Gas Supply Transportation		5.7181	(0.0319)	5.6862
4.08		Gas Supply Commodity - System		13.6109	(0.0506)	13.5608
		Gas Supply Commodity - Buy/Sell		13.5944	(0.0506)	13.5444
	RATE 110					
5.01		Customer Charge		$587.37	$22.45	$609.82
5.02		Demand Charge (Cents/Month/m³)		22.9100	0.0000	22.9100
5.03		Delivery Charge	first 1,000,000	0.5945	0.0713	0.6659
5.04			over 1,000,000	0.4445	0.0713	0.5159
5.05		Load Balancing Commodity		0.1637	(0.0284)	0.1353
5.06		Gas Supply Transportation		5.7181	(0.0319)	5.6862
5.07		Gas Supply Commodity - System		13.5786	(0.0201)	13.5585
5.08		Gas Supply Commodity - Buy/Sell		13.5562	(0.0201)	13.5361

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2011-0296 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2011-0277 cents *
	RATE 115					
1.01		Customer Charge		$622.62	$0.00	$622.62
1.02		Demand Charge (Cents/Month/m³)		24.3600	0.0000	24.3600
1.03		Delivery Charge	first 1,000,000	0.3229	(0.0562)	0.2667
1.04			over 1,000,000	0.2229	(0.0562)	0.1667
1.05		Load Balancing Commodity		0.0545	(0.0038)	0.0507
1.06		Gas Supply Transportation		5.7181	(0.0319)	5.6862
1.07		Gas Supply Commodity - System		13.5786	(0.0201)	13.5585
1.08		Gas Supply Commodity - Buy/Sell		13.5562	(0.0201)	13.5361
	RATE 125					
2.01		Customer Charge		$ 500.00	$0.00	$ 500.00
2.02		Delivery Charge (Cents/Month/m³ of Contract Dmnd)		9.0792	0.1300	9.2092
	RATE 135	DEC - MAR				
3.00		Customer Charge		$115.08	$4.16	$119.24
3.01		Delivery Charge	first 14,000	6.7603	0.0558	6.8162
3.02			next 28,000	5.5603	0.0558	5.6162
3.03			over 42,000	5.1603	0.0558	5.2162
3.04		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.05		Gas Supply Transportation		5.7181	(0.0319)	5.6862
3.06		Gas Supply Commodity - System		13.6594	(0.0249)	13.6345
3.07		Gas Supply Commodity - Buy/Sell		13.6370	(0.0249)	13.6121
	RATE 135	APR - NOV				
3.08		Customer Charge		$115.08	$4.16	$119.24
3.09		Delivery Charge	first 14,000	2.0603	0.0558	2.1162
3.10			next 28,000	1.3603	0.0558	1.4162
3.11			over 42,000	1.1603	0.0558	1.2162
3.12		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.13		Gas Supply Transportation		5.7181	(0.0319)	5.6862
3.14		Gas Supply Commodity - System		13.6594	(0.0249)	13.6345
3.15		Gas Supply Commodity - Buy/Sell		13.6370	(0.0249)	13.6121
	RATE 145					
4.00		Customer Charge		$123.34	$4.65	$127.99
4.01		Demand Charge (Cents/Month/m³)		8.2300	0.000	8.2300
4.02		Delivery Charge	first 14,000	2.8051	0.0830	2.8881
4.03			next 28,000	1.4461	0.0830	1.5291
4.04			over 42,000	0.8871	0.0830	0.9701
4.05		Gas Supply Load Balancing		0.3557	(0.1453)	0.2104
4.06		Gas Supply Transportation		5.7181	(0.0319)	5.6862
4.07		Gas Supply Commodity - System		13.7438	(0.0192)	13.7246
4.08		Gas Supply Commodity - Buy/Sell		13.7214	(0.0192)	13.7022
	RATE 170					
5.00		Customer Charge		$279.31	$10.27	$289.58
5.01		Demand Charge (Cents/Month/m³)		4.0900	0.0000	4.0900
5.02		Delivery Charge	first 1,000,000	0.5168	0.0306	0.5474
5.03			over 1,000,000	0.3168	0.0306	0.3474
5.04		Gas Supply Load Balancing		0.1978	(0.0784)	0.1194
5.05		Gas Supply Transportation		5.7181	(0.0319)	5.6862
5.06		Gas Supply Commodity - System		13.5786	(0.0201)	13.5585
5.07		Gas Supply Commodity - Buy/Sell		13.5562	(0.0201)	13.5361

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2011-0296 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2011-0277 cents *
	RATE 200					
1.00		Customer Charge		$0.00	$0.00	$0.00
1.01		Demand Charge (Cents/Month/m³)		14.7000	0.0000	14.7000
1.02		Delivery Charge		1.1423	0.1158	1.2581
1.03		Gas Supply Load Balancing		0.6670	(0.0986)	0.5684
1.04		Gas Supply Transportation		5.7181	(0.0319)	5.6862
1.05		Gas Supply Commodity - System		13.5786	(0.0201)	13.5585
1.06		Gas Supply Commodity - Buy/Sell		13.5562	(0.0201)	13.5361
	RATE 300	FIRM SERVICE				
2.00		Monthly Customer Charge		$500.00	$0.00	$500.00
2.01		Demand Charge (Cents/Month/m³)		24.9253	0.3570	25.2824
		INTERRUPTIBLE SERVICE				
2.02		Minimum Delivery Charge (Cents/Month/m³)		0.3582	0.0051	0.3633
2.03		Maximum Delivery Charge (Cents/Month/m³)		0.9834	0.0140	0.9974
	RATE 315					
		Monthly Customer Charge		$150.00	$0.00	$150.00
3.00		Space Demand Chg (Cents/Month/m³)		0.0585	(0.0018)	0.0567
3.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		15.7936	0.3187	16.1123
3.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.3475	(0.0092)	0.3383
	RATE 320					
4.00		Backstop	All Gas Sold	19.8113	(0.0999)	19.7114
	RATE 316					
		Monthly Customer Charge		$150.00	$0.00	$150.00
5.00		Space Demand Chg (Cents/Month/m³)		0.0585	(0.0018)	0.0567
5.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		5.2711	(0.1266)	5.1445
5.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.1049	(0.0000)	0.1049

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2011-0296 cents *	Col. 4 Change cents *	Col. 5 EB-2011-0277 cents *
	RATE 325					
		Transmission & Compression				
1.00		Demand Charge - ATV ($/Month/10³ m³)		0.1870	0.0046	0.1916
1.01		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		16.9047	0.4155	17.3202
1.02		Commodity Charge		0.9660	(0.0006)	0.9654
		Storage				
1.03		Demand Charge - ATV ($/Month/10*3 m³)		0.2253	0.0020	0.2273
1.04		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		20.4355	0.1824	20.6179
1.05		Commodity Charge		0.3280	(0.0038)	0.3242
	RATE 330	Storage Service - Firm				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.00		Minimum		0.4123	0.0066	0.4189
2.01		Maximum		2.0615	0.0330	2.0945
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.02		Minimum		37.3402	0.5979	37.9381
2.03		Maximum		186.7010	2.9895	189.6905
		Commodity Charge				
2.04		Minimum		1.2940	(0.0044)	1.2896
2.05		Maximum		6.4700	($0.0220)	6.4480
		Storage Service - Interruptible				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.06		Minimum		0.4123	0.0066	0.4189
2.07		Maximum		2.0615	0.0330	2.0945
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.08		Minimum		29.8722	0.4783	30.3505
2.09		Maximum		149.3608	$2.3916	151.7524
		Commodity Charge				
2.10		Minimum		1.2940	(0.0044)	1.2896
2.11		Maximum		6.4700	(0.0220)	6.4480
		Storage Service - Off Peak				
		Commodity Charge				
2.12		Minimum		0.6752	0.0019	0.6771
2.13		Maximum		38.4629	0.4901	38.9530
	RATE 331	Tecumseh Transmission Service				
		Firm				
		Demand Charge ($/Month/10³ m³ of				
3.00		Maximum Contracted Daily Delivery)		5.2700	0.0330	5.3030
		Interruptible				
3.01		Commodity Charge ($/10³m³ of gas delivered)		0.2080	0.0010	0.2090

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

CALCULATION OF GAS SUPPLY CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF GAS SUPPLY CHARGE												
	GAS SUPPLY COSTS ($000)												
1.1	Annual Commodity	888,719	499,266	354,264	139	-	8,688	-	83	2,888	6,716	16,676	
1.2	Bad Debt Commodity	7,417	3,593	3,789	-	-	-	-	0	35	-	-	
1.3	System Gas Fee	1,472	827	587	0	-	14	-	0	5	11	28	
1.4	Return on Rate Base - Working Cash	1,159	651	462	0	-	11	-	0	4	9	22	
1	Total Commodity Costs	898,767	504,337	359,101	139	-	8,714	-	84	2,932	6,736	16,725	
	VOLUMES (10^3 m^3)												
2.1	System and Buy/Sell Volumes	6,574,095	3,693,205	2,620,584	1,027	-	64,267	-	613	21,365	49,679	123,354	
2.2	System Volumes	6,574,095	3,693,205	2,620,584	1,027	-	64,267	-	613	21,365	49,679	123,354	
	GAS SUPPLY CHARGE SYSTEM (¢/m^3)												
3.1	Annual Commodity	13.5185	13.5185	13.5185	13.5185	-	13.5185	13.5185	13.5185	13.5185	13.5185	13.5185	1.1 / 2.1
3.2	Bad Debt Commodity	0.1128	0.0973	0.1446	-	-	-	-	0.0760	0.1660	-	-	1.2 / 2.1
3.3	System Gas Fee	0.0224	0.0224	0.0224	0.0224	-	0.0224	0.0224	0.0224	0.0224	0.0224	0.0224	1.3 / 2.2
3.4	Return on Rate Base - Working Cash	0.0176	0.0176	0.0176	0.0176	-	0.0176	0.0176	0.0176	0.0176	0.0176	0.0176	1.4 / 2.1
3	System Gas Supply Charge	13.6713	13.6558	13.7031	13.5585	-	13.5585	13.5585	13.6345	13.7246	13.5585	13.5585	
	GAS SUPPLY CHARGE BUY/SELL(¢/m3)												
4.1	Annual Commodity	13.5185	13.5185	13.5185	13.5185	-	13.5185	13.5185	13.5185	13.5185	13.5185	13.5185	1.1 / 2.1
4.2	Bad Debt Commodity	0.1128	0.0973	0.1446	-	-	-	-	0.0760	0.1660	-	-	1.2 / 2.1
4.3	Return on Rate Base - Working Cash	0.0176	0.0176	0.0176	0.0176	-	0.0176	0.0176	0.0176	0.0176	0.0176	0.0176	1.4 / 2.1
4	Buy/Sell Gas Supply Charge	13.6490	13.6334	13.6807	13.5361	-	13.5361	13.5361	13.6121	13.7022	13.5361	13.5361	

CALCULATION OF GAS SUPPLY LOAD BALANCING & TRANSPORTATION CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF LOAD BALANCING CHARGES												
	ANNUAL LOAD BALANCING COSTS ($000)												
5.1	Peak	44,167	24,007	19,374	1	-	272	60	-	-	-	453	
5.2	Seasonal	3,421	1,573	1,646	(0)	-	39	21	-	33	62	47	
5.3	Return on Rate Base - Gas in Inventory	30,641	14,085	14,746	(1)	-	349	189	-	292	558	421	
5	Total Load Balancing	78,229	39,665	35,767	0	-	660	270	-	325	621	922	
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,268,896	4,583,338	4,772,169	1,177	-	488,031	532,453	55,183	154,354	519,974	162,216	
7	**ANNUAL LOAD BALANCING CHARGE (¢/m3)**		0.8654	0.7495	0.0037	-	0.1353	0.0507	-	0.2104	0.1194	0.5684	5.0 / 6
	DERIVATION OF TRANSPORTATION CHARGES												
8	Pipeline Annual incl. some M12 (upstream	442,874	227,622	191,613	58	-	9,101	569	1,233	2,409	3,254	7,014	
	VOLUMES (10^3 m^3)												
9	Total Transportation Volumes	7,788,644	4,003,100	3,369,817	1,027	-	160,062	10,015	21,679	42,372	57,218	123,354	
10	**PROPOSED TRANSPORTATION CHARGE (¢/m^3)**		5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	

CALCULATION OF SEASONAL CREDIT FOR RATE 135, 145, 170 & 200

RATE 135		
Seasonal Credits Applicable to Rate 135	**$**	**(465)**
Annual Volume (103 m3)		55,183
Mean Daily Volume (103 m3)		151
Annual Seasonal Credits	$	(3.08)
Payable from December to March	$	(0.77)
RATE 145		
Seasonal Credits Applicable to Rate 145	**$**	**(846)**
Annual Volume (103 m3)		154,354
Mean Daily Volume (103 m3)		
16 Hours		423
72 Hours		-
Annual Seasonal Credits		
16 Hours	$	(2.00)
Payable from December to March	$	(0.50)
72 Hours	$	(0.45)
Payable from December to March	$	(0.11)
Seasonal Credits Applicable to Rate 145		
16 Hours	$	(846)
72 Hours	$	-
RATE 170		
Seasonal Credits Applicable to Rate 170	**$**	**(6,268)**
Annual Volume (103 m3)		519,974
Mean Daily Volume (103 m3)		1,425
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)
RATE 200		
Seasonal Credits Applicable to Rate 200	**$**	**(196)**
Annual Volume (103 m3)		16,257
Mean Daily Volume (103 m3)		45
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m^3		Col. 2 EB-2011-0277 Bills & Volumes $10^3\ m^3$	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 1					
1.1	Customer Charge	Bills		21,921,543	$20.00	438,431
1.2	Delivery Charge	first	30	617,569	7.5104	46,382
1.3		next	55	860,715	7.0265	60,478
1.4		next	85	964,788	6.6474	64,134
1.5		over	170	2,140,266	6.3651	136,231
1.	Total Distribution Charge			4,583,338		745,656
2.1	Gas Supply Load Balancing			4,583,338	0.8654	39,665
2.2	Gas Supply Transportation			4,003,100	5.6862	227,622
3.1	Gas Supply Commodity - System			3,693,205	13.6558	504,337
3.2	Gas Supply Commodity - Buy/Sell			0	13.6334	0
3.	Total Gas Supply Charge			3,693,205		504,337
4.1	TOTAL DISTRIBUTION			4,583,338		745,656
4.2	TOTAL GAS SUPPLY LOAD BALANCING			4,583,338		267,287
4.3	TOTAL GAS SUPPLY COMMODITY			3,693,205		504,337
4.	TOTAL RATE 1			**4,583,338**		1,517,279
5.	Adj. Factor		0.9999			
6.	ADJUSTED REVENUE					**1,517,190**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2011-0277 Bills & Volumes 10³ m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 6				
1.1	Customer Charge	Bills	1,889,984	$70.00	132,299
1.2	Delivery Charge	First 500	545,743	7.1184	38,848
1.3		Next 1050	656,613	5.4417	35,731
1.4		Next 4500	1,164,219	4.2678	49,687
1.5		Next 7000	695,918	3.5133	24,450
1.6		Next 15250	602,312	3.1781	19,142
1.7		Over 28300	1,107,364	3.0942	34,264
1.	Total Distribution Charge		4,772,169		334,420
2.1	Gas Supply Load Balancing		4,772,169	0.7495	35,767
2.2	Gas Supply Transportation		3,369,817	5.6862	191,613
3.1	Gas Supply Commodity - System		2,620,584	13.7031	359,101
3.2	Gas Supply Commodity - Buy/Sell		0	13.6807	0
3.	Total Gas Supply Charge		2,620,584		359,101
4.1	TOTAL DISTRIBUTION		4,772,169		334,420
4.2	TOTAL GAS SUPPLY LOAD BALANCING		4,772,169		227,380
4.3	TOTAL GAS SUPPLY COMMODITY		2,620,584		359,101
4.	TOTAL RATE 6		**4,772,169**		920,901
5.	Adj. Factor	1.000			
6.	ADJUSTED REVENUE				**920,847**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Rate Block m^3	Bills & Volumes 10^3 m^3	Rate cents*	Revenues $000
		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2011-0277		
	RATE 9				
1.1	Customer Charge	Bills	108	$242.18	26
1.2	Delivery Charge	first 20000	966	11.0385	107
1.3		over 20000	211	10.3323	22
1.	Total Distribution Charge		1,177		155
2.1	Gas Supply Load Balancing		1,177	0.0037	0
2.2	Gas Supply Transportation		1,027	5.6862	58
3.1	Gas Supply Commodity - System		1,027	13.5585	139
3.2	Gas Supply Commodity - Buy/Sell		0	13.5361	0
3.	Total Gas Supply Charge		1,027		139
4.1	TOTAL DISTRIBUTION		1,177		155
4.2	TOTAL GAS SUPPLY LOAD BALANCING		1,177		58
4.3	TOTAL GAS SUPPLY COMMODITY		1,027		139
4	TOTAL RATE 9		**1,177**		**352**

		Rate Block m^3	Contracts & Volumes 10^3 m^3	Rate cents*	Revenues $000
			EB-2011-0277		
	RATE 100				
1.1	Customer Charge	Contracts	0	$126.67	0
1.2	Demand Charge		0	8.19	0
1.3	Delivery Charge	first 14,000	0	5.2427	0
1.4		next 28,000	0	3.8837	0
1.5		over 42,000	0	3.3247	0
1	Total Distribution Charge		0		0
2.1	Gas Supply Load Balancing		0	0.4882	0
2.2	Gas Supply Transportation		0	5.6862	0
3.1	Gas Supply Commodity - System		0	13.5608	0
3.2	Gas Supply Commodity - Buy/Sell		0	13.5444	0
3	Total Gas Supply Charge		0		0
4.1	TOTAL DISTRIBUTION		0		0
4.2	TOTAL GAS SUPPLY LOAD BALANCING		0		0
4.3	TOTAL GAS SUPPLY COMMODITY		0		0
4	TOTAL RATE 100		**0**		**0**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2011-0277		
Item No.		Rate Block m³	Contracts & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 110				
1.1	Customer Charge	Contracts	2,436	$609.82	1,486
1.2	Demand Charge		28,041	22.9100	6,424
1.3	Delivery Charge	first 1,000,000	448,335	0.6659	2,985
1.4		over 1,000,000	39,696	0.5159	205
1.	Total Distribution Charge		488,031		11,100
2.1	Load Balancing Commodity		488,031	0.1353	660
2.2	Gas Supply Transportation		160,062	5.6862	9,101
2.	Total Gas Supply Load Balancing				9,761
3.1	Gas Supply Commodity - System		64,267	13.5585	8,714
3.2	Gas Supply Commodity - Buy/Sell		0	13.5361	0
3.	Total Gas Supply Charge		64,267		8,714
4.1	TOTAL DISTRIBUTION		488,031		11,100
4.2	TOTAL GAS SUPPLY LOAD BALANCING		488,031		9,761
4.3	TOTAL GAS SUPPLY COMMODITY		64,267		8,714
4.	TOTAL RATE 110		**488,031**		**29,575**

			EB-2011-0277		
		Rate Block m³	Contracts & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 115				
6.6	Customer Charge	Contracts	360	$622.62	224
6.2	Demand Charge		21,320	24.3600	5,193
6.3	Delivery Charge	first 1,000,000	155,980	0.2667	416
6.4		over 1,000,000	376,474	0.1667	628
6	Total Distribution Charge		532,453		6,461
7.1	Load Balancing Commodity		532,453	0.0507	270
7.2	Gas Supply Transportation		10,015	5.6862	569
7	Total Gas Supply Load Balancing				839
8.1	Gas Supply Commodity - System		0	13.5585	0
8.2	Gas Supply Commodity - Buy/Sell		0	13.5361	0
8.	Total Gas Supply Charge		0		0
9.1	TOTAL DISTRIBUTION		532,453		6,461
9.2	TOTAL GAS SUPPLY LOAD BALANCING		532,453		839
9.3	TOTAL GAS SUPPLY COMMODITY		0		0
9.	TOTAL RATE 115		**532,453**		**7,301**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2011-0277 Contracts & Volumes 10^3 m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 125				
1.1	Customer Charge		56	$ 500.00	28
1.2	Demand Charge		106,168	9.2092	9,777
1.	Total Distribution Charge		106,168		9,805

Item No.		Rate Block m³	EB-2011-0277 Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 135				
	DEC to MAR				
1.1	Customer Charge	Contracts	152	$119.24	18
1.2	Delivery Charge	first 14,000	547	6.8162	37
1.3		next 28,000	865	5.6162	49
1.4		over 42,000	2,700	5.2162	141
1.	Total Distribution Charge		4,112		245
2.1	Gas Supply Load Balancing		4,112	0.0000	0
2.2	Gas Supply Transportation		1,536	5.6862	87
2.3	Seasonal Credit				(465)
3.1	Gas Supply Commodity - System		80	13.6345	11
3.2	Gas Supply Commodity - Buy/Sell		0	13.6121	0
3.	Total Gas Supply Charge		80		11
4.	SUB-TOTAL WINTER				-122
	APR to NOV				
5.1	Customer Charge	Contracts	304	$119.24	36
5.2	Delivery Charge	first 14,000	4,008	2.1162	85
5.3		next 28,000	7,758	1.4162	110
5.4		over 42,000	39,305	1.2162	478
5.	Total Distribution Charge		51,071		709
6.1	Gas Supply Load Balancing		51,071	0.0000	0
6.2	Gas Supply Transportation		20,143	5.6862	1,145
7.1	Gas Supply Commodity - System		533	13.6345	73
7.2	Gas Supply Commodity - Buy/Sell		0	13.6121	0
7.	Total Gas Supply Charge		533		73
8.	SUB-TOTAL SUMMER				1,927
9.1	TOTAL DISTRIBUTION		55,183		954
9.2	TOTAL GAS SUPPLY LOAD BALANCING		55,183		768
9.3	TOTAL GAS SUPPLY COMMODITY		613		84
9.	TOTAL RATE 135		**55,183**		**1,805**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2011-0277 Contracts & Volumes 10^3 m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 145				
1.1	Customer Charge	Contracts	1,284	$127.99	164
1.2	Demand Charge		16,197	8.2300	1,333
1.2	Delivery Charge	first 14,000	16,769	2.8881	484
1.3		next 28,000	30,427	1.5291	465
1.4		over 42,000	107,157	0.9701	1,040
1.	Total Distribution Charge		154,354		3,486
2.1	Gas Supply Load Balancing		154,354	0.2104	325
2.2	Gas Supply Transportation		42,372	5.6862	2,409
2.3	Curtailment Credit				(846)
3.1	Gas Supply Commodity - System		21,365	13.7246	2,932
3.2	Gas Supply Commodity - Buy/Sell		0	13.7022	0
3.	Total Gas Supply Charge		21,365		2,932
4.1	TOTAL DISTRIBUTION		154,354		3,486
4.2	TOTAL GAS SUPPLY LOAD BALANCING		154,354		1,888
4.3	TOTAL GAS SUPPLY COMMODITY		21,365		2,932
4.	TOTAL RATE 145		**154,354**		**8,307**

		Rate Block m³	EB-2011-0277 Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 170				
6.6	Customer Charge	Contracts	456	$289.58	132
6.2	Demand Charge		47,406	4.0900	1,939
6.3	Delivery Charge	first 1,000,000	325,530	0.5474	1,782
6.4		over 1,000,000	194,444	0.3474	675
6	Total Distribution Charge		519,974		4,528
7.1	Gas Supply Load Balancing		519,974	0.1194	621
7.7	Gas Supply Transportation		57,218	5.6862	3,254
7.3	Curtailment Credit				(6,268)
8.1	Gas Supply Commodity - System		49,679	13.5585	6,736
8.2	Gas Supply Commodity - Buy/Sell		0	13.5361	0
8.	Total Gas Supply Charge		49,679		6,736
9.1	TOTAL DISTRIBUTION		519,974		4,528
9.2	TOTAL GAS SUPPLY LOAD BALANCING		519,974		(2,394)
9.3	TOTAL GAS SUPPLY COMMODITY		49,679		6,736
9.	TOTAL RATE 170		**519,974**		**8,870**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2011-0277 Contracts & Volumes 10^3 m³	Col. 3 EB-2011-0277 Rate cents*	Col. 4 EB-2011-0277 Revenues $000
	RATE 200				
1.1	Customer Charge	Contracts	12	$0.00	0
1.2	Demand Charge		13,622	14.7000	2,002
1.3	Delivery Charge		162,216	1.2581	2,041
1.	Total Distribution Charge		162,216		4,043
2.1	Gas Supply Load Balancing		162,216	0.5684	922
2.2	Gas Supply Transportation		123,354	5.6862	7,014
2.3	Curtailment Credit				(196)
3.1	Gas Supply Commodity - System		123,354	13.5585	16,725
3.2	Gas Supply Commodity - Buy/Sell		0	13.5361	0
3.	Total Gas Supply Charge		123,354		16,725
4.1	TOTAL DISTRIBUTION		162,216		4,043
4.2	TOTAL GAS SUPPLY LOAD BALANCING		162,216		7,740
4.3	TOTAL GAS SUPPLY COMMODITY		123,354		16,725
4.	TOTAL RATE 200		**162,216**		**28,508**

		Rate Block m³	EB-2011-0277 Contracts & Volumes 10^3 m³	EB-2011-0277 Rate cents*	EB-2011-0277 Revenues $000
	RATE 300				
	Firm				
	Customer Charge		96	$500.00	48
	Demand Charge		887	25.2824	224
	Interruptible				
	Minimum Delivery Charge		31,049	0.3633	113
	Maximum Delivery Charge		0	0.9974	0
8.	TOTAL RATE 300		**0**		**385**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				Heating, Water Htg. & Other Uses			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	240.00	228.00	12.00	5.3%	240.00	228.00	12.00	5.3%
1.3	DISTRIBUTION CHG.	$	205.11	200.03	5.08	2.5%	309.26	301.58	7.68	2.5%
1.4	LOAD BALANCING	§ $	200.73	204.50	(3.77)	-1.8%	307.35	313.10	(5.75)	-1.8%
1.5	SALES COMMDTY	$	418.43	419.43	(1.00)	-0.2%	640.59	642.15	(1.56)	-0.2%
1.6	TOTAL SALES	$	1,064.27	1,051.96	12.31	1.2%	1,497.20	1,484.83	12.37	0.8%
1.7	TOTAL T-SERVICE	$	645.84	632.53	13.31	2.1%	856.61	842.68	13.93	1.7%
1.8	SALES UNIT RATE	$/m³	0.3473	0.3433	0.0040	1.2%	0.3192	0.3165	0.0026	0.8%
1.9	T-SERVICE UNIT RATE	$/m³	0.2108	0.2064	0.0043	2.1%	0.1826	0.1796	0.0030	1.7%
1.10	SALES UNIT RATE	$/GJ	9.216	9.109	0.1066	1.2%	8.468	8.398	0.0700	0.8%
1.11	T-SERVICE UNIT RATE	$/GJ	5.593	5.477	0.1153	2.1%	4.845	4.766	0.0788	1.7%

			Heating Only				Heating & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	240.00	228.00	12.00	5.3%	240.00	228.00	12.00	5.3%
2.3	DISTRIBUTION CHG.	$	131.55	128.30	3.25	2.5%	136.91	133.50	3.41	2.6%
2.4	LOAD BALANCING	§ $	128.07	130.50	(2.43)	-1.9%	131.36	133.82	(2.46)	-1.8%
2.5	SALES COMMDTY	$	266.98	267.61	(0.63)	-0.2%	273.79	274.46	(0.67)	-0.2%
2.6	TOTAL SALES	$	766.60	754.41	12.19	1.6%	782.06	769.78	12.28	1.6%
2.7	TOTAL T-SERVICE	$	499.62	486.80	12.82	2.6%	508.27	495.32	12.95	2.6%
2.8	SALES UNIT RATE	$/m³	0.3921	0.3859	0.0062	1.6%	0.3901	0.3839	0.0061	1.6%
2.9	T-SERVICE UNIT RATE	$/m³	0.2556	0.2490	0.0066	2.6%	0.2535	0.2470	0.0065	2.6%
2.10	SALES UNIT RATE	$/GJ	10.404	10.238	0.1654	1.6%	10.349	10.187	0.1625	1.6%
2.11	T-SERVICE UNIT RATE	$/GJ	6.781	6.607	0.1740	2.6%	6.726	6.555	0.1714	2.6%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	240.00	228.00	12.00	5.3%	240.00	228.00	12.00	5.3%
3.3	DISTRIBUTION CHG.	$	332.60	324.33	8.27	2.5%	77.25	75.35	1.90	2.5%
3.4	LOAD BALANCING	§ $	330.71	336.93	(6.22)	-1.8%	70.82	72.14	(1.32)	-1.8%
3.5	SALES COMMDTY	$	689.34	691.02	(1.68)	-0.2%	147.63	147.98	(0.35)	-0.2%
3.6	TOTAL SALES	$	1,592.65	1,580.28	12.37	0.8%	535.70	523.47	12.23	2.3%
3.7	TOTAL T-SERVICE	$	903.31	889.26	14.05	1.6%	388.07	375.49	12.58	3.4%
3.8	SALES UNIT RATE	$/m³	0.3155	0.3131	0.0025	0.8%	0.4956	0.4842	0.0113	2.3%
3.9	T-SERVICE UNIT RATE	$/m³	0.1789	0.1762	0.0028	1.6%	0.3590	0.3474	0.0116	3.4%
3.10	SALES UNIT RATE	$/GJ	8.371	8.306	0.0650	0.8%	13.148	12.848	0.3002	2.3%
3.11	T-SERVICE UNIT RATE	$/GJ	4.748	4.674	0.0738	1.6%	9.525	9.216	0.3088	3.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				**Com. Htg., Air Cond'ng & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	840.00	780.00	60.00	7.7%	840.00	780.00	60.00	7.7%
1.3	DISTRIBUTION CHG.	$	1,217.81	1,196.53	21.28	1.8%	1,562.51	1,535.19	27.32	1.8%
1.4	LOAD BALANCING	§ $	1,454.84	1,486.47	(31.63)	-2.1%	1,884.23	1,925.18	(40.95)	-2.1%
1.5	SALES COMMDTY	$	3,097.72	3,109.15	(11.43)	-0.4%	4,011.98	4,026.82	(14.84)	-0.4%
1.6	TOTAL SALES	$	6,610.37	6,572.15	38.22	0.6%	8,298.72	8,267.19	31.53	0.4%
1.7	TOTAL T-SERVICE	$	3,512.65	3,463.00	49.65	1.4%	4,286.74	4,240.37	46.37	1.1%
1.8	SALES UNIT RATE	$/m³	0.2924	0.2907	0.0017	0.6%	0.2834	0.2824	0.0011	0.4%
1.9	T-SERVICE UNIT RATE	$/m³	0.1554	0.1532	0.0022	1.4%	0.1464	0.1448	0.0016	1.1%
1.10	SALES UNIT RATE	$/GJ	7.758	7.714	0.0449	0.6%	7.520	7.492	0.0286	0.4%
1.11	T-SERVICE UNIT RATE	$/GJ	4.123	4.064	0.0583	1.4%	3.885	3.843	0.0420	1.1%

			Medium Commercial Customer				**Large Commercial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	840.00	780.00	60.00	7.7%	840.00	780.00	60.00	7.7%
2.3	DISTRIBUTION CHG.	$	6,558.15	6,443.39	114.76	1.8%	12,007.67	11,797.49	210.18	1.8%
2.4	LOAD BALANCING	§ $	10,912.46	11,149.65	(237.19)	-2.1%	21,824.86	22,299.21	(474.35)	-2.1%
2.5	SALES COMMDTY	$	23,235.39	23,321.19	(85.80)	-0.4%	46,470.62	46,642.23	(171.61)	-0.4%
2.6	TOTAL SALES	$	41,546.00	41,694.23	(148.23)	-0.4%	81,143.15	81,518.93	(375.78)	-0.5%
2.7	TOTAL T-SERVICE	$	18,310.61	18,373.04	(62.43)	-0.3%	34,672.53	34,876.70	(204.17)	-0.6%
2.8	SALES UNIT RATE	$/m³	0.2450	0.2459	(0.0009)	-0.4%	0.2393	0.2404	(0.0011)	-0.5%
2.9	T-SERVICE UNIT RATE	$/m³	0.1080	0.1084	(0.0004)	-0.3%	0.1022	0.1028	(0.0006)	-0.6%
2.10	SALES UNIT RATE	$/GJ	6.501	6.524	(0.0232)	-0.4%	6.348	6.378	(0.0294)	-0.5%
2.11	T-SERVICE UNIT RATE	$/GJ	2.865	2.875	(0.0098)	-0.3%	2.713	2.729	(0.0160)	-0.6%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	840.00	780.00	60.00	7.7%	840.00	780.00	60.00	7.7%
3.3	DISTRIBUTION CHG.	$	2,159.02	2,121.28	37.74	1.8%	2,895.66	2,845.01	50.65	1.8%
3.4	LOAD BALANCING	§ $	2,785.65	2,846.21	(60.56)	-2.1%	4,112.57	4,201.96	(89.39)	-2.1%
3.5	SALES COMMDTY	$	5,931.39	5,953.30	(21.91)	-0.4%	8,756.70	8,789.05	(32.35)	-0.4%
3.6	TOTAL SALES	$	11,716.06	11,700.79	15.27	0.1%	16,604.93	16,616.02	(11.09)	-0.1%
3.7	TOTAL T-SERVICE	$	5,784.67	5,747.49	37.18	0.6%	7,848.23	7,826.97	21.26	0.3%
3.8	SALES UNIT RATE	$/m³	0.2707	0.2703	0.0004	0.1%	0.2598	0.2600	(0.0002)	-0.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1336	0.1328	0.0009	0.6%	0.1228	0.1225	0.0003	0.3%
3.10	SALES UNIT RATE	$/GJ	7.182	7.172	0.0094	0.1%	6.894	6.899	(0.0046)	-0.1%
3.11	T-SERVICE UNIT RATE	$/GJ	3.546	3.523	0.0228	0.6%	3.259	3.250	0.0088	0.3%

			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	840.00	780.00	60.00	7.7%	840.00	780.00	60.00	7.7%
4.3	DISTRIBUTION CHG.	$	6,715.89	6,598.40	117.49	1.8%	12,124.90	11,912.69	212.21	1.8%
4.4	LOAD BALANCING	§ $	10,912.45	11,149.64	(237.19)	-2.1%	21,824.81	22,299.12	(474.31)	-2.1%
4.5	SALES COMMDTY	$	23,235.39	23,321.18	(85.79)	-0.4%	46,470.52	46,642.10	(171.58)	-0.4%
4.6	TOTAL SALES	$	41,703.73	41,849.22	(145.49)	-0.3%	81,260.23	81,633.91	(373.68)	-0.5%
4.7	TOTAL T-SERVICE	$	18,468.34	18,528.04	(59.70)	-0.3%	34,789.71	34,991.81	(202.10)	-0.6%
4.8	SALES UNIT RATE	$/m³	0.2459	0.2468	(0.0009)	-0.3%	0.2396	0.2407	(0.0011)	-0.5%
4.9	T-SERVICE UNIT RATE	$/m³	0.1089	0.1093	(0.0004)	-0.3%	0.1026	0.1032	(0.0006)	-0.6%
4.10	SALES UNIT RATE	$/GJ	6.526	6.548	(0.0228)	-0.3%	6.358	6.387	(0.0292)	-0.5%
4.11	T-SERVICE UNIT RATE	$/GJ	2.890	2.899	(0.0093)	-0.3%	2.722	2.738	(0.0158)	-0.6%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
1.2	CUSTOMER CHG.	$	1,520.04	1,464.12	55.92	3.8%	1,520.04	1,464.12	55.92	3.8%
1.3	DISTRIBUTION CHG.	$	18,034.88	17,625.93	408.95	2.3%	28,768.86	28,047.19	721.67	2.6%
1.4	LOAD BALANCING	$	20,942.81	21,399.04	(456.23)	-2.1%	36,957.95	37,763.08	(805.12)	-2.1%
1.5	SALES COMMDTY	$	45,996.74	46,166.59	(169.85)	-0.4%	81,170.84	81,470.56	(299.72)	-0.4%
1.6	TOTAL SALES	$	86,494.47	86,655.68	(161.21)	-0.2%	148,417.69	148,744.95	(327.25)	-0.2%
1.7	TOTAL T-SERVICE	$	40,497.73	40,489.09	8.64	0.0%	67,246.85	67,274.39	(27.53)	0.0%
1.8	SALES UNIT RATE	$/m³	0.2550	0.2555	(0.0005)	-0.2%	0.2480	0.2485	(0.0005)	-0.2%
1.9	T-SERVICE UNIT RATE	$/m³	0.1194	0.1194	0.0000	0.0%	0.1123	0.1124	(0.0000)	0.0%
1.10	SALES UNIT RATE	$/GJ	6.766	6.778	(0.0126)	-0.2%	6.579	6.593	(0.0145)	-0.2%
1.11	T-SERVICE UNIT RATE	$/GJ	3.168	3.167	0.0007	0.0%	2.981	2.982	(0.0012)	0.0%

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Industrial Firm				**Rate 100 - Average Industrial Firm**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
2.2	CUSTOMER CHG.	$	1,520.04	1,464.12	55.92	3.8%	1,520.04	1,464.12	55.92	3.8%
2.3	DISTRIBUTION CHG.	$	18,307.69	17,898.72	408.97	2.3%	29,010.29	28,288.59	721.70	2.6%
2.4	LOAD BALANCING	$	20,942.81	21,399.04	(456.23)	-2.1%	36,957.89	37,763.01	(805.12)	-2.1%
2.5	SALES COMMDTY	$	45,996.72	46,166.56	(169.84)	-0.4%	81,170.70	81,470.41	(299.71)	-0.4%
2.6	TOTAL SALES	$	86,767.26	86,928.44	(161.18)	-0.2%	148,658.92	148,986.13	(327.21)	-0.2%
2.7	TOTAL T-SERVICE	$	40,770.54	40,761.88	8.66	0.0%	67,488.22	67,515.72	(27.50)	0.0%
2.8	SALES UNIT RATE	$/m³	0.2558	0.2563	(0.0005)	-0.2%	0.2484	0.2489	(0.0005)	-0.2%
2.9	T-SERVICE UNIT RATE	$/m³	0.1202	0.1202	0.0000	0.0%	0.1127	0.1128	(0.0000)	0.0%
2.10	SALES UNIT RATE	$/GJ	6.787	6.800	(0.0126)	-0.2%	6.589	6.604	(0.0145)	-0.2%
2.11	T-SERVICE UNIT RATE	$/GJ	3.189	3.189	0.0007	0.0%	2.992	2.993	(0.0012)	0.0%

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				**Rate 145 - Average Commercial Interr.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,535.88	1,480.08	55.80	3.8%	1,535.88	1,480.08	55.80	3.8%
3.3	DISTRIBUTION CHG.	$	10,062.56	9,781.18	281.38	2.9%	14,696.32	14,199.74	496.58	3.5%
3.4	LOAD BALANCING	$	18,139.86	18,740.95	(601.09)	-3.2%	32,011.94	33,072.71	(1,060.77)	-3.2%
3.5	SALES COMMDTY	$	46,552.19	46,617.32	(65.13)	-0.1%	82,151.06	82,265.99	(114.93)	-0.1%
3.6	TOTAL SALES	$	76,290.49	76,619.53	(329.04)	-0.4%	130,395.20	131,018.52	(623.32)	-0.5%
3.7	TOTAL T-SERVICE	$	29,738.30	30,002.21	(263.91)	-0.9%	48,244.14	48,752.53	(508.39)	-1.0%
3.8	SALES UNIT RATE	$/m³	0.2249	0.2259	(0.0010)	-0.4%	0.2178	0.2189	(0.0010)	-0.5%
3.9	T-SERVICE UNIT RATE	$/m³	0.0877	0.0885	(0.0008)	-0.9%	0.0806	0.0814	(0.0008)	-1.0%
3.10	SALES UNIT RATE	$/GJ	5.968	5.993	(0.0257)	-0.4%	5.780	5.808	(0.0276)	-0.5%
3.11	T-SERVICE UNIT RATE	$/GJ	2.326	2.347	(0.0206)	-0.9%	2.138	2.161	(0.0225)	-1.0%
			Rate 145 - Small Industrial Interr.				**Rate 145 - Average Industrial Interr.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,535.88	1,480.08	55.80	3.8%	1,535.88	1,480.08	55.80	3.8%
4.3	DISTRIBUTION CHG.	$	10,335.35	10,053.97	281.38	2.8%	14,937.77	14,441.21	496.56	3.4%
4.4	LOAD BALANCING	$	18,139.85	18,740.94	(601.09)	-3.2%	32,011.89	33,072.64	(1,060.75)	-3.2%
4.5	SALES COMMDTY	$	46,552.18	46,617.33	(65.15)	-0.1%	82,150.91	82,265.84	(114.93)	-0.1%
4.6	TOTAL SALES	$	76,563.26	76,892.32	(329.06)	-0.4%	130,636.45	131,259.77	(623.32)	-0.5%
4.7	TOTAL T-SERVICE	$	30,011.08	30,274.99	(263.91)	-0.9%	48,485.54	48,993.93	(508.39)	-1.0%
4.8	SALES UNIT RATE	$/m³	0.2257	0.2267	(0.0010)	-0.4%	0.2182	0.2193	(0.0010)	-0.5%
4.9	T-SERVICE UNIT RATE	$/m³	0.0885	0.0893	(0.0008)	-0.9%	0.0810	0.0819	(0.0008)	-1.0%
4.10	SALES UNIT RATE	$/GJ	5.989	6.015	(0.0257)	-0.4%	5.791	5.818	(0.0276)	-0.5%
4.11	T-SERVICE UNIT RATE	$/GJ	2.348	2.368	(0.0206)	-0.9%	2.149	2.172	(0.0225)	-1.0%

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				**Rate 110 - Average Ind. Firm - 50% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,317.84	7,048.44	269.40	3.8%	7,317.84	7,048.44	269.40	3.8%
5.3	DISTRIBUTION CHG.	$	13,035.98	12,609.17	426.81	3.4%	213,490.77	206,377.37	7,113.40	3.4%
5.4	LOAD BALANCING	$	34,845.13	35,206.42	(361.29)	-1.0%	580,751.55	586,773.09	(6,021.54)	-1.0%
5.5	SALES COMMDTY	$	81,156.85	81,277.13	(120.28)	-0.1%	1,352,612.37	1,354,617.56	(2,005.19)	-0.1%
5.6	TOTAL SALES	$	136,355.80	136,141.16	214.64	0.2%	2,154,172.53	2,154,816.46	(643.93)	0.0%
5.7	TOTAL T-SERVICE	$	55,198.95	54,864.03	334.92	0.6%	801,560.16	800,198.90	1,361.26	0.2%
5.8	SALES UNIT RATE	$/m³	0.2278	0.2274	0.0004	0.2%	0.2159	0.2160	(0.0001)	0.0%
5.9	T-SERVICE UNIT RATE	$/m³	0.0922	0.0917	0.0006	0.6%	0.0803	0.0802	0.0001	0.2%
5.10	SALES UNIT RATE	$/GJ	6.044	6.035	0.0095	0.2%	5.729	5.731	(0.0017)	0.0%
5.11	T-SERVICE UNIT RATE	$/GJ	2.447	2.432	0.0148	0.6%	2.132	2.128	0.0036	0.2%

			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,317.84	7,048.44	269.40	3.8%	7,471.44	7,471.44	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	166,532.86	159,419.45	7,113.41	4.5%	826,851.72	866,082.92	(39,231.20)	-4.5%
6.4	LOAD BALANCING	$	580,751.48	586,772.99	(6,021.51)	-1.0%	4,006,216.20	4,031,204.14	(24,987.94)	-0.6%
6.5	SALES COMMDTY	$	1,352,612.23	1,354,617.41	(2,005.18)	-0.1%	9,468,286.97	9,482,323.37	(14,036.40)	-0.1%
6.6	TOTAL SALES	$	2,107,214.41	2,107,858.29	(643.88)	0.0%	14,308,826.33	14,387,081.87	(78,255.54)	-0.5%
6.7	TOTAL T-SERVICE	$	754,602.18	753,240.88	1,361.30	0.2%	4,840,539.36	4,904,758.50	(64,219.14)	-1.3%
6.8	SALES UNIT RATE	$/m³	0.2112	0.2113	(0.0001)	0.0%	0.2049	0.2060	(0.0011)	-0.5%
6.9	T-SERVICE UNIT RATE	$/m³	0.0756	0.0755	0.0001	0.2%	0.0693	0.0702	(0.0009)	-1.3%
6.10	SALES UNIT RATE	$/GJ	5.604	5.606	(0.0017)	0.0%	5.436	5.466	(0.0297)	-0.5%
6.11	T-SERVICE UNIT RATE	$/GJ	2.007	2.003	0.0036	0.2%	1.839	1.864	(0.0244)	-1.3%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				Rate 170 - Average Ind. Interr. - 50% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,430.88	1,380.96	49.92	3.6%	3,474.96	3,351.72	123.24	3.7%
7.3	DISTRIBUTION CHG.	$	8,704.1	8,369.88	334.18	4.0%	79,661.9	76,608.49	3,053.40	4.0%
7.4	LOAD BALANCING	$	28,989.96	29,181.15	(191.19)	-0.7%	458,907.33	469,916.98	(11,009.65)	-2.3%
7.5	SALES COMMDTY	$	81,611.62	81,760.67	(149.05)	-0.2%	1,352,612.37	1,354,617.56	(2,005.19)	-0.1%
7.6	TOTAL SALES	$	120,736.52	120,692.66	43.86	0.0%	1,894,656.55	1,904,494.75	(9,838.20)	-0.5%
7.7	TOTAL T-SERVICE	$	39,124.90	38,931.99	192.91	0.5%	542,044.18	549,877.19	(7,833.01)	-1.4%
7.8	SALES UNIT RATE	$/m³	0.2017	0.2016	0.0001	0.0%	0.1899	0.1909	(0.0010)	-0.5%
7.9	T-SERVICE UNIT RATE	$/m³	0.0654	0.0650	0.0003	0.5%	0.0543	0.0551	(0.0008)	-1.4%
7.10	SALES UNIT RATE	$/GJ	5.352	5.350	0.0019	0.0%	5.039	5.065	(0.0262)	-0.5%
7.11	T-SERVICE UNIT RATE	$/GJ	1.734	1.726	0.0086	0.5%	1.442	1.462	(0.0208)	-1.4%

			Rate 170 - Average Ind. Interr. - 75% LF				Rate 170 - Large Ind. Interr. - 75% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,474.96	3,351.72	123.24	3.7%	3,474.96	3,351.72	123.24	3.7%
8.3	DISTRIBUTION CHG.	$	72,477.1	69,423.66	3,053.40	4.4%	391,771.1	370,397.36	21,373.76	5.8%
8.4	LOAD BALANCING	$	458,907.26	469,916.95	(11,009.69)	-2.3%	3,212,351.49	3,289,419.13	(77,067.64)	-2.3%
8.5	SALES COMMDTY	$	1,352,612.23	1,354,617.41	(2,005.18)	-0.1%	9,468,286.97	9,482,323.37	(14,036.40)	-0.1%
8.6	TOTAL SALES	$	1,887,471.51	1,897,309.74	(9,838.23)	-0.5%	13,075,884.54	13,145,491.58	(69,607.04)	-0.5%
8.7	TOTAL T-SERVICE	$	534,859.28	542,692.33	(7,833.05)	-1.4%	3,607,597.57	3,663,168.21	(55,570.64)	-1.5%
8.8	SALES UNIT RATE	$/m³	0.1892	0.1902	(0.0010)	-0.5%	0.1872	0.1882	(0.0010)	-0.5%
8.9	T-SERVICE UNIT RATE	$/m³	0.0536	0.0544	(0.0008)	-1.4%	0.0517	0.0525	(0.0008)	-1.5%
8.10	SALES UNIT RATE	$/GJ	5.020	5.046	(0.0262)	-0.5%	4.968	4.994	(0.0264)	-0.5%
8.11	T-SERVICE UNIT RATE	$/GJ	1.422	1.443	(0.0208)	-1.4%	1.371	1.392	(0.0211)	-1.5%

Witnesses: J. Collier
A. Kacicnik

Measure of 2012 Revenues vs 2012 Revenue Requirement
December 31, 2012

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col.10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Sales and Delivery Revenue	2,536.78	1,517.19	920.85	0.35	0.00	29.58	7.30	9.81	1.81	8.31	8.87	28.51	0.39	1.62	2.21
2.	Unbilled Revenues	7.51	1.97	5.03	0.00	0.00	0.23	0.02	0.00	0.00	0.17	0.08	0.00	0.00	0.00	0.00
3.	Total Revenues	2,544.29	1,519.16	925.88	0.35	0.00	29.81	7.32	9.81	1.81	8.48	8.95	28.51	0.39	1.62	2.21
4.	Proposed 2012 Revenue Requirement	2,544.29	1,518.95	924.40	0.46	0.00	30.47	6.72	10.05	2.01	9.03	9.37	28.55	0.47	1.62	2.21
5.	Measure of Revenues vs Revenue Requirement	1.00	1.00	1.00	0.76	0.00	0.98	1.09	0.98	0.90	0.94	0.96	1.00	0.82	1.00	1.00

Measure of 2012 Revenues vs 2012 Revenue Requirement
Excluding Gas Supply Commodity
December 31, 2012

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col.10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Sales and Delivery Revenue	1,638.01	1,012.85	561.75	0.21	0.00	20.86	7.30	9.81	1.72	5.37	2.13	11.78	0.39	1.62	2.21
2.	Unbilled Revenues	7.51	1.97	5.03	0.00	0.00	0.23	0.02	0.00	0.00	0.17	0.08	0.00	0.00	0.00	0.00
3.	Total Revenues	1,645.52	1,014.83	566.78	0.21	0.00	21.09	7.32	9.81	1.72	5.55	2.22	11.78	0.39	1.62	2.21
4.	Proposed 2012 Revenue Requirement	1,645.53	1,014.61	565.30	0.32	0.00	21.75	6.72	10.05	1.92	6.09	2.63	11.83	0.47	1.62	2.21
5.	Measure of Revenues vs Revenue Requirement excluding Gas Supply Commodity	1.00	1.00	1.00	0.66	0.00	0.97	1.09	0.98	0.90	0.91	0.84	1.00	0.82	1.00	1.00

Total 2012 Revenue Requirement

December 31, 2012

(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE	Reference
1	PRODUCT COSTS	898.8	504.3	359.1	0.1	-	8.7	-	-	0.1	2.9	6.7	16.7	-	-	-	Ex.B/T3/S10/P4/L1 & Ex.B/T3/S10/P5/L1
2	PIPELINE TRANS. AND LOAD BALANCING	513.8	267.7	227.4	0.1	-	9.7	0.7	-	1.2	1.9	(2.5)	7.7	-	-	-	Ex.B/T3/S10/P4/L2 & Ex.B/T3/S10/P5/L2
3	STORAGE	156.3	79.3	71.6	(0.0)	-	1.3	0.7	-	(0.5)	0.7	1.3	1.9	-	-	-	Ex.B/T3/S10/P4/L3 & Ex.B/T3/S10/P5/L3
4	DISTRIBUTION	505.9	292.7	181.9	0.0	0.0	9.0	4.7	9.6	0.3	2.8	2.9	1.6	0.3	0.1	-	Ex.B/T3/S10/P4/L4 & Ex.B/T3/S10/P5/L4
5	CUSTOMER RELATED	467.9	374.9	84.3	0.2	0.0	1.9	0.7	0.5	0.8	0.7	0.9	0.7	0.1	0.0	2.2	Ex.B/T3/S10/P5/L5
Total 2012 Revenue Requirement		2,542.7	1,518.8	924.3	0.5	0.0	30.7	6.7	10.1	2.0	9.0	9.4	28.6	0.3	0.2	2.2	

2012 Gas Cost to Operations Revenue Requirement

December 31, 2012

(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE	Allocation
	SUPPLY COSTS																
	PRODUCT COSTS																
1.1	Annual Commodity	888.7	499.2	354.2	0.1	-	8.7	-	-	0.1	2.9	6.7	16.7	-	-	-	1.1
1	Total Gas Cost	888.7	499.2	354.2	0.1	-	8.7	-	-	0.1	2.9	6.7	16.7	-	-	-	-
	PIPELINE TRANS. AND LOAD BALANCING																
2.1	Peak	44.2	24.1	19.1	-	-	0.4	0.1	-	-	-	-	0.5	-	-	-	3.1
2.2	Seasonal	2.3	1.1	1.1	(0.0)	-	0.0	0.0	-	-	0.0	0.0	0.0	-	-	-	3.2
2.3	Annual - Transportation	446.6	229.5	193.2	0.1	-	9.2	0.6	-	1.2	2.4	3.3	7.1	-	-	-	1.4
2.4	Seasonal Credit	(7.3)	-	-	-	-	-	-	-	-	(0.8)	(6.3)	(0.2)	-	-	-	-
2	Total Pipeline Trans. Cost	485.8	254.8	213.5	0.1	-	9.6	0.7	-	1.2	1.6	(2.9)	7.4	-	-	-	-
	STORAGE																
3.1	Deliverability	63.0	34.4	27.3	-	-	0.5	0.2	-	-	-	-	0.6	-	-	-	3.1
3.2	Space	58.3	26.8	28.1	(0.0)	-	0.7	0.4	-	-	0.6	1.1	0.8	-	-	-	3.2
3.3	Seasonal Credit	(0.5)	-	-	-	-	-	-	-	(0.5)	-	-	-	-	-	-	-
3	Total Storage	120.9	61.2	55.3	(0.0)	-	1.2	0.5	-	(0.5)	0.6	1.1	1.4	-	-	-	-
	DISTRIBUTION																
4.1	Commodity	19.9	8.1	8.4	0.0	-	0.9	0.9	-	0.1	0.3	0.9	0.3	-	-	-	1.2
4	Total Distribution	19.9	8.1	8.4	0.0	-	0.9	0.9	-	0.1	0.3	0.9	0.3	-	-	-	-
	Total 2012 Gas Cost to Operations Revenue Requirement	1,515.3	823.3	631.5	0.2	-	20.3	2.2	-	1.0	5.3	5.8	25.8	-	-	-	-

2012 Distribution Revenue Requirement

December 31, 2012

(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	SUPPLY RELATED															
1	PRODUCT RELATED	10.1	5.1	4.9	0.0	-	0.0	-	-	0.0	0.0	0.0	0.1	-	-	-
2	LOAD BALANCING RELATED	28.0	12.9	14.0	(0.0)	-	0.1	(0.0)	-	(0.0)	0.3	0.4	0.4	-	-	-
	FACILITIES' COSTS															
3	STORAGE	35.5	18.0	16.3	(0.0)	-	0.1	0.1	-	-	0.2	0.3	0.4	-	-	-
4	DISTRIBUTION	486.0	284.6	173.4	0.0	0.0	8.2	3.7	9.6	0.2	2.6	2.0	1.3	0.3	0.1	-
5	CUSTOMER RELATED	467.9	374.9	84.3	0.2	0.0	1.9	0.7	0.5	0.8	0.7	0.9	0.7	0.1	0.0	2.2
Total 2012 Distribution Revenue Requirement		1,027.4	695.5	292.8	0.3	0.0	10.3	4.6	10.1	1.0	3.7	3.6	2.8	0.3	0.2	2.2

2012 Y- and Z- Factor Revenue Requirement
December 31, 2012
(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300 Firm	Col. 14 RATE 300 Int	Col. 15 DIRECT PURCHASE	Col. 16 Assignment
	Y Factor: Other																
1.1	2012 Gas in Storage and Working Cash Carrying Cost	30.6	14.1	14.7	(0.0)	0.0	0.3	0.2	0.0	0.0	0.3	0.6	0.4	0.0	0.0		3.2
1.2	2012 DSM Program Costs*	23.8	7.5	12.4	0.0	0.0	1.7	0.4	0.0	0.1	0.9	0.9	0.0	0.0	0.0		Direct
1.3	2012 DSM Low Income*	7.1	4.8	2.0	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0		EB-2010-0146 ExB T3 S10 p5
1.4	2012 CIS/ Customer Care	99.2	91.3	7.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		4.1
		160.7	117.7	37.0	0.0	0.0	2.1	0.7	0.1	0.1	1.2	1.5	0.4	0.0	0.0		
	Y Factor: Capital Investment																
1.5	2012 Leave to Construct	6.6	3.0	2.7	0.0	0.0	0.1	0.1	0.6	0.0	0.0	0.0	0.1	0.0	0.0		2.1
		6.6	3.0	2.7	0.0	0.0	0.1	0.1	0.6	0.0	0.0	0.0	0.1	0.0	0.0		
1.6	**Total Y-Factor: Other & Capital Investment**	167.3	120.7	39.7	0.0	0.0	2.2	0.8	0.6	0.1	1.2	1.5	0.5	0.0	0.0		
	Z Factor: Proposed																
1.7	2012 Pension Funding requirement	17.7	12.0	5.1	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	0.0	ExB T3 S10 p7
1.8	2012 Crossbore/Sewer Lateral Program requirement	3.8	3.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.2
1.9	Total Z-Factor (Proposed)	21.5	15.4	5.4	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	0.0	
2.0	**Total All Y- & Z-Factors**	188.8	136.1	45.1	0.0	0.0	2.4	0.8	0.8	0.2	1.3	1.6	0.6	0.0	0.0	0.0	
	* Note: 2012 Total DSM Y-factor amount (1.2 + 1.3)	30.9	12.3	14.4	0.0	0.0	1.7	0.5	0.1	0.1	0.9	0.9	0.0	0.0	0.0	0.0	

2012 Distribution Revenue Requirement with Y- and Z- Factor Detail
December 31, 2012
(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300 Firm	Col. 14 RATE 300 Int	Col. 15 DIRECT PURCHASE	Col. 16
1.0	DRR before Y- & Z- Factors	838.6	559.4	247.7	0.3	0.0	8.0	3.7	9.2	0.9	2.4	2.1	2.2	0.3	0.2	2.2	
	Y Factor: Other																
1.1	2012 Gas in Storage and Working Cash Carrying Cost	30.6	14.1	14.7	(0.0)	-	0.3	0.2	0.0	0.0	0.3	0.6	0.4	0.0	-	-	
1.2	2012 DSM Program Costs*	23.8	7.5	12.4	-	-	1.7	0.4	0.0	0.1	0.9	0.9	0.0	0.0	-	-	
1.3	2012 DSM Low Income*	7.1	4.8	2.0	0.0	-	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	-	-	
1.4	2012 CIS/ Customer Care	99.2	91.3	7.9	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	
	Y Factor: Capital Investment																
1.5	2012 Leave to Construct	6.6	3.0	2.7	0.0	-	0.1	0.1	0.6	0.0	0.0	0.0	0.1	0.0	-	-	
1.6	**Total Y-Factor**	167.3	120.7	39.7	0.0	-	2.2	0.8	0.6	0.1	1.2	1.5	0.5	0.0	0.0	-	
1.7	**DRR with Y-Factors**	1,005.9	680.1	287.4	0.3	0.0	10.2	4.5	9.9	1.0	3.6	3.6	2.7	0.3	0.2	2.2	
	Z Factor: Proposed																allocated in proportion
1.8	2012 Pension Funding requirement	17.7	12.0	5.1	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	-	to Line 1.7
1.9	2012 Crossbore/Sewer Lateral Program requirement	3.8	3.4	0.4	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	
2.0	Total Z-Factor (Proposed)	21.5	15.4	5.4	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	-	
2.1	**Total 2012 DRR with All Y-& Z-Factors**	1,027.4	695.5	292.8	0.3	0.0	10.3	4.6	10.1	1.0	3.7	3.6	2.8	0.3	0.2	2.2	
	* Note:																
	2012 Total DSM Y-factor amount (1.2 + 1.3)	30.9	12.3	14.4	0.0	0.0	1.7	0.5	0.1	0.1	0.9	0.9	0.0	0.0	0.0	0.0	

Allocators
December 31, 2012

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
	FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	6,574.1	3,693.2	2,620.6	1.0	0.0	64.3	0.0	0.0	0.6	21.4	49.7	123.4	0.0	0.0	0.0
1.2 Bundled Annual Deliveries	11,268.9	4,583.3	4,772.2	1.2	0.0	488.0	532.5	0.0	55.2	154.4	520.0	162.2	0.0	0.0	0.0
1.3 Total Annual Deliveries	11,299.9	4,583.3	4,772.2	1.2	0.0	488.0	532.5	0.0	55.2	154.4	520.0	162.2	0.0	31.0	0.0
1.4 Bundled Transportation Deliveries	7,788.6	4,003.1	3,369.8	1.0	0.0	160.1	10.0	0.0	21.7	42.4	57.2	123.3	0.0	0.0	0.0
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	108,100.6	48,892.8	44,030.3	2.3	0.0	1,977.5	1,700.4	9,530.1	7.1	408.2	249.6	1,222.8	79.6	0.0	0.0
2.2 Delivery Demand HP	97,448.4	48,892.8	44,030.3	2.3	0.0	1,977.5	1,700.4	0.0	7.1	408.2	249.6	0.0	79.6	100.7	0.0
2.3 Delivery Demand LP	96,220.4	48,892.8	44,030.3	2.3	0.0	1,977.5	472.5	0.0	7.1	408.2	249.6	0.0	79.6	100.7	0.0
2.4 Cust. Rel Plant	1,984,734.0	1,826,796.0	157,500.0	9.0	0.0	201.0	30.0	5.0	38.0	108.0	38.0	1.0	7.0	1.0	0.0
STORAGE RESPONSIBILITY															
3.1 Deliverability	50.8	27.7	22.0	0.0	0.0	0.4	0.1	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0
3.2 Space	2,823.6	1,298.0	1,358.9	(0.1)	0.0	32.2	17.4	0.0	0.0	26.9	51.5	38.8	0.0	0.0	0.0
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1,984,734.0	1,826,796.0	157,500.0	9.0	0.0	201.0	30.0	5.0	38.0	108.0	38.0	1.0	7.0	1.0	0.0
4.2 Services	1,982,400.0	1,784,240.1	195,204.2	18.4	0.0	1,066.4	255.1	3.1	254.8	682.9	618.3	0.0	40.3	16.3	0.0

Allocation Percentages
December 31, 2012

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
	FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	1.0000	0.5618	0.3986	0.0002	0.0000	0.0098	0.0000	0.0000	0.0001	0.0032	0.0076	0.0188	0.0000	0.0000	0.0000
1.2 Bundled Annual Deliveries	1.0000	0.4067	0.4235	0.0001	0.0000	0.0433	0.0472	0.0000	0.0049	0.0137	0.0461	0.0144	0.0000	0.0000	0.0000
1.3 Total Annual Deliveries	1.0000	0.4056	0.4223	0.0001	0.0000	0.0432	0.0471	0.0000	0.0049	0.0137	0.0460	0.0144	0.0000	0.0027	0.0000
1.4 Bundled Transportation Deliveries	1.0000	0.5140	0.4327	0.0001	0.0000	0.0206	0.0013	0.0000	0.0028	0.0054	0.0073	0.0158	0.0000	0.0000	0.0000
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	1.0000	0.4523	0.4073	0.0000	0.0000	0.0183	0.0157	0.0882	0.0001	0.0038	0.0023	0.0113	0.0007	0.0000	0.0000
2.2 Delivery Demand HP	1.0000	0.5017	0.4518	0.0000	0.0000	0.0203	0.0174	0.0000	0.0001	0.0042	0.0026	0.0000	0.0008	0.0010	0.0000
2.3 Delivery Demand LP	1.0000	0.5081	0.4576	0.0000	0.0000	0.0206	0.0049	0.0000	0.0001	0.0042	0.0026	0.0000	0.0008	0.0010	0.0000
2.4 Cust. Rel Plant	1.0000	0.9204	0.0794	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
STORAGE RESPONSIBILITY															
3.1 Deliverability	1.0000	0.5464	0.4325	0.0000	0.0000	0.0084	0.0025	0.0000	0.0000	0.0000	0.0000	0.0103	0.0000	0.0000	0.0000
3.2 Space	1.0000	0.4597	0.4813	0.0000	0.0000	0.0114	0.0062	0.0000	0.0000	0.0095	0.0182	0.0138	0.0000	0.0000	0.0000
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1.0000	0.9204	0.0794	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
4.2 Services	1.0000	0.9000	0.0985	0.0000	0.0000	0.0005	0.0001	0.0000	0.0001	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000

GAS COSTS, TRANSPORTATION, AND STORAGE

1. The purpose of this evidence is to provide an overview of the gas cost consequences of the gas supply activities, including storage and transportation of Enbridge Gas Distribution Inc. (the "Company" or "Enbridge") during the 2012 Test Year. The process for calculating budgeted gas costs is consistent with prior years. Using the forecasted volumetric demand requirements the Company develops a gas supply plan using a model known as "SENDOUT". This model determines the optimum monthly supply portfolio using existing contractual parameters, i.e., transportation contracts including storage deliverability and also provides the Company with a forecast of monthly storage targets. Once the monthly supply portfolio and storage targets have been established then gas costs can be calculated.

Gas Supply

2. Enbridge expects to acquire its system gas supply under the following types of contracts during the Test Year:

- Western Canadian Supplies: These supplies source gas in the supply area of Western Canada and will be transported either via TransCanada PipeLines Limited ("TransCanada") or via Alliance Pipeline to the Company's franchise area.
- Ontario Production: The Ontario supply is *de minimus* in relative terms.
- Peaking contracts: These contracts source gas from other suppliers in the Eastern Zone during the winter season.
- Chicago Supply: These supplies are to be acquired in Chicago and transported to Dawn via the Company's contracted capacity on the Vector Pipeline.

- Delivered Supply: These supplies are forecasted to be acquired directly at the Dawn. However, the Company may consider alternative sources such as western Canadian supply utilizing TCPL STFT capacity either for economic or operational reasons.

Enbridge currently buys all of its gas on an indexed basis. It does not have any existing contracts that provide supply on a fixed price basis. The Company expects to continue this practice for its 2012 gas supply arrangements.

3. The following is Enbridge's forecast of gas supply acquisition during the test year:

	Volume	
Contract Type	10^6m^3	Bcf
Western Canadian Supply	3 439.8	124.4
Ontario Production	0.7	0.0
Peaking	37.3	1.3
Chicago Supply	1837.1	64.9
Delivered Supply	1488.8	52.6
	6803.7	240.2

Commodity Costs

4. The price assumptions reflect the market's assessment (as at the time of preparation of this evidence) of the different expected delivery points for the Company's forecast of gas supply.

5. The market's assessment is determined at any point in time by the use of the simple average of forward quoted prices as reported by various media and other services,

over a period of 21 business days for a basket of pricing points, and pricing indices that reflect the Company's gas supply acquisition arrangements.

6. The Company prepared its gas supply forecast based upon a 21-day average of various indices from August 3, 2011 to August 31, 2011 for the 12 months commencing January 1, 2012 and applied these monthly prices to the 2012 budgeted annual volume gas purchases.

7. In an effort to remove the impact of commodity costs changes the Company removed the impact of the updated price forecast and the October 1, 2011 QRAM prices in a fashion similar to the 2011 Budget that was filed in EB-2010-0146, Enbridge's 2010 rate adjustment application.

8. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2012 PGVA. Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2012 PGVA. While the Company does not anticipate acquiring gas in 2012 via means other than the traditional transportation paths (i.e., TCPL, Alliance/Vector) the possibility does exist in the future to acquire gas via alternative means (i.e., Shale Gas, Rockies, Renewable Natural Gas).

Peak Day Coverage

9. Enbridge continues to plan for its peak day coverage based on the 20% probability, multi-peak day design conditions introduced in the EBRO 490 proceeding. These conditions assume 39.5 degree days (Celsius) for the coldest peak. It is assumed these conditions are experienced, on average, about once every five years.

Enbridge is forecasting a design peak day level of 99 280 10^3m^3 (3.5 Bcf) during the winter season of the test year.

Transportation

10. Enbridge has a number of Firm Transportation ("FT") and other service entitlements in place for system gas sourced in Western Canada or in the United States (at the Chicago hub as well as U.S. supply area), or both, during the test year. These include service entitlements with TransCanada, Alliance Pipeline and Vector Pipeline. For purposes of this forecast contracts were priced based upon current tolls and contracts that have an expiry date during the Test Year were deemed to be renewed with the following exceptions. The Company and intervenors participated in a System Reliability proceeding (EB-2010-0231) and the outcome of that proceeding has been included as a part of the 2012 gas supply portfolio. As per the EB-2010-0231 Settlement Agreement the Company assigned 50,000 Gj/day of TCPL shorthaul capacity to Direct Purchase customers and has acquired 50,000 Gj/day of TCPL STFT from November to March. The Company also incorporated in its plan the acquisition of 200,000 Gj/day of TCPL STFT for three winter months which was also agreed upon as part of the settlement agreement as a substitute for traditional peaking services.

11. During 2011 the Company administered a TCPL FT Turnback process with its Direct Purchase customers in accordance with the System Reliability proceeding mentioned above. The Company received a limited number of requests but they were rejected because they did not meet the criteria established in the System Reliability proceeding. Therefore, there was no change to the Company's contracted TCPL FT capacity for November 1, 2011 stemming from FT Turnback. During the System Reliability proceeding Enbridge expressed some concerns about

the reliability of its current Peaking Supply contracts. Enbridge had observed that largely the same suppliers were providing Peaking Supply, Direct Purchase supply, and Curtailment Delivered Supply ("CDS"). During January 2011 and February 2011when curtailment was called by Enbridge those concerns became a reality. Certain Direct Purchase customers had their MDV deliveries cut by their suppliers as well as cuts with respect to CDS nominations. In addition, the Company did not receive deliveries as a result of one of the peaking suppliers having their supplies cut. This has led the Company to lower the amount of traditional peaking supplies that it will plan to acquire in 2012. To compensate for this reduction the Company has included an additional 75,000 Gj/day of TCPL STFT for three winter months. The Company has also taken an assignment of 26,956 Gj/day of TCPL-FT Empress to Iroquois capacity.

12. The Company also has M12 service entitlements with Union Gas totaling 2,225,102 GJ/d (2,081 MMcf/d) for delivery of gas by Union at Dawn for storage injection or onward transportation, for gas withdrawn from storage at Tecumseh or Union, or both, and for gas sourced in Western Canada or the United States, or both, and delivered at Dawn for onward transportation. The Company also has M16 transportation capacity with Union to facilitate the Chatham "D" Storage pool. The gas cost forecast assumed January 1, 2011 Union tolls.

Storage

13. The Company has underground storage of its own at Tecumseh near Corunna in southwestern Ontario and at Crowland near Welland in the Niagara Region. Tecumseh is a large multiple-cycle facility, whereas Crowland is a small peak shaving facility.

14. Enbridge also held a storage entitlement with Union Gas Limited for 21,259,700 GJ broken down into three contracts with varied expiry dates. In its decision in the NGEIR proceeding dated November 7, 2006 the Board ruled that these contracts should be priced at cost of service rates and that a phased in approach to market based storage was in the best interests of customers in Ontario. Effective April 1, 2010 all of the Company's contracted third party storage is at market based rates.

15. During 2011 the Company issued an RFP for three market based storage contracts that expire March 31, 2012. The cost consequences of these and the other third party storage contracts have been included in the forecast for 2012 gas costs.

<u>Energy Content</u>

16. Enbridge has used a gross heating value of 37.69 MJ/m^3 to convert quantities (i.e., GJ, Dth) into volumes (i.e., 10^3m^3, MMcf). Quantities are the units specified in many of Enbridge's gas purchase and transportation service agreements, whereas Enbridge rates are volumetric.

<u>Schedules</u>

17. The Gas Cost schedules at Exhibit B, Tab 4, Schedule 2, provide the following: Pages 1 and 2 provide the summary of the forecasted gas cost to operations for 2012 based upon an updated supply and transportation portfolio to meet the forecasted volumetric requirement for 2012. Page 3 provides a breakdown of the forecasted 2012 storage and transportation costs that are shown at Item #13, Column 2 of page 2. Page 4 provides a breakdown of the monthly gas in storage balances for rate base purposes in 2012. Pages 5 through 8 are the comparable schedules for 2011 assuming the October 1, 2011 QRAM Reference Price.

Summary of Gas Cost to Operations
Year ended December 31, 2012

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $\$/10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	1,597,128.1	214,603.4	134.368	3.565
1.3	Western - @ Nova - TCPL	943,063.3	133,838.3	141.919	3.765
1.4	Western Buy/Sell - with Fuel	1,854.8	267.4	144.146	3.825
1.5	Western - @ Alliance	957,382.1	141,515.2	147.815	3.922
1.6	Less TCPL Fuel Requirement	(59,603.3)	0.0		
1.	Total Western Canadian Supplies	3,439,824.9	490,224.4	142.514	3.781
2.	Peaking Supplies	37,242.5	10,064.5	270.242	7.170
3.	Ontario Production	730.0	160.0	219.169	5.815
4.	Chicago Supplies	1,837,120.7	300,419.2	163.527	4.339
5.	Delivered Supplies	1,488,789.8	252,144.0	169.362	4.494
6.	Total Supply Costs	6,803,707.9	1,053,012.1	154.770	4.106
	Transportation Costs				
7.1	TCPL - FT - Demand		197,326.2		
7.2	- FT - Commodity	2,482,442.8	13,451.6	5.419	0.144
7.3	- Parkway to CDA		3,238.4		
7.4	- STS - CDA		5,793.8		
7.5	- STS - EDA		4,687.0		
7.6	- Dawn to CDA		9,471.0		
7.7	- Dawn to EDA		22,582.0		
7.8	- Dawn to Iroquois		7,063.3		
7.9	Other Charges		(2,541.6)		
7.10	Nova Transmission		7,039.6		
7.11	Alliance Pipeline		42,485.0		
7.12	Vecto Pipeline		25,272.4		
7.	Total Transportation Costs		335,868.7		
8.	Total Before PGVA Adjustment	6,803,707.9	1,388,880.7	204.136	5.416
9.	PGVA Adjustment		(65,066.0)		
10.	Total Purchases & Receipt	6,803,707.9	1,323,814.7	194.573	5.162

Summary of Gas Cost to Operations
Year ended December 31, 2012

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	6,803,707.9	1,323,814.7	194.573	5.162
11.	Storage Fluctuation	(86,079.7)	(16,748.7)		
12.	Commodity Cost to Operations	6,717,628.2	1,307,066.0	194.573	
13.	Storage and Transportation Costs		110,101.3		
14.	Gas Cost to Operations	6,717,628.2	1,417,167.2	210.962	5.597
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		98,337.9		
17.	Forecasted Gas Costs	6,717,628.2	1,515,505.2	225.601	5.986
	Regulatory Adjustments				
18.	NGV Vehicles		0.0		
19.	LRAM Adjustment		0.0		
20.	Accounting Adjustments		0.0		
21.	Forecasted Utility Gas Costs	6,717,628.2	1,515,505.2	225.601	5.986

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2012

Item #			
1.	Sendout To Operations	6,717,628.2	
2.	T-Service Volumes	4,658,767.4	4,658,767.3
3.	Total Sendout	11,376,395.6	
4.1	Residential Sales	3,693,205.3	
4.2	Commercial Sales	2,305,946.1	
4.3	Industrial Sales	451,589.4	
4.4	T-Service	4,655,938.9	
4.5	Rate 200 T-Service (Gazifere)	38,862.2	
4.6	Rate 200 Sales (Gazifere)	122,562.8	
4.7	Company Use	6,656.9	
4.8	Unaccounted For (UAF)	68,925.0	
4.9	Unbilled Forecast - Sales	44,979.3	
4.10	Unbilled Forecast - T-Service	(36,033.8)	
4.11	Lost and Unaccounted For (LUF)	23,763.5	
4.12	LUF Capitalized	0.0	
4.	Total System Requirements	11,376,395.6	

Witness: D. Small

Summary of Storage & Transportion Costs
Fiscal 2012

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2012	Col. 2 Fiscal 2012 Storage Charges Recovered in Fiscal 2012	Col. 3 Fiscal 2011 Storage Charges Recovered in Fiscal 2012	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2012
	Storage				
1.1	Chatham D	132.3	75.0	57.2	132.2
1.2	Injection	125.5	37.6	80.5	118.1
1.3	Withdrawal	114.4	114.4	0.0	114.4
1.5	Market Based Storage	20,170.7	11,423.1	10,045.1	21,468.1
1.6	Other	878.7	878.7	75.7	954.4
1.	Total Storage	21,421.7	12,528.8	10,258.5	22,787.3
2.	Total Transportation	65,550.7	36,054.3	29,506.5	65,560.8
	Dehydration				
3.1	Demand	1,001.1	550.6	450.6	1,001.2
3.2	Commodity	189.4	189.4	0.0	189.4
3.	Total Dehydration	1,190.5	740.0	450.6	1,190.7
4.	Total Storage & Other Costs	88,162.9	49,323.2	40,215.5	89,538.7
	Fuel Costs				
5.1	Tecumseh	3,686.6	2,337.3	1,064.6	3,401.9
5.2	Union Storage	1,157.0	743.4	370.1	1,113.5
5.3	Union Transportation	16,044.5	15,730.0	317.1	16,047.1
5.	Total Fuel Costs	20,888.1	18,810.7	1,751.8	20,562.5
6.	Total Storage & Transportation	109,051.0	68,133.9	41,967.4	110,101.3
7.	Storage and Transportation Costs Charged to Gas Cost to Operations				110,101.3

Witness: D. Small

2012
Gas in Storage
Month End Balances and
Average of Monthly Averages

Item #		10^3m^3	Value ($000)
Month end balances except @ January 1			
1.	January 1	1,442,118.7	383,974.0
2.	January	930,232.6	252,476.0
3.	February	529,243.3	147,951.4
4.	March	220,644.4	74,070.7
5.	April	134,726.6	63,297.0
6.	May	441,808.8	133,526.4
7.	June	838,486.0	223,075.6
8.	July	1,328,035.0	331,053.0
9.	August	1,820,458.4	439,617.0
10.	September	2,204,413.7	526,439.8
11.	October	2,303,765.4	554,688.0
12.	November	2,020,812.1	494,699.8
13.	December	1,528,198.4	381,064.4
14.	Average of Averages	1,188,148.7	301,951.2

Witness: D. Small

Summary of Gas Cost to Operations
Year ended December 31, 2011

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	1,111,440.1	144,748.3	130.235	3.455
1.3	Western - @ Nova - TCPL	691,069.2	95,318.8	137.930	3.660
1.4	Western Buy/Sell - with Fuel	1,413.9	200.1	141.536	3.755
1.5	Western - @ Alliance	963,416.6	137,745.8	142.976	3.793
1.6	Less TCPL Fuel Requirement	(61,259.4)	0.0		
1.	Total Western Canadian Supplies	2,706,080.4	378,013.1	139.690	3.706
2.	Peaking Supplies	52,410.0	10,752.0	205.151	5.443
3.	Ontario Production	1,460.1	313.3	214.563	5.693
4.	Chicago Supplies	1,846,482.9	292,110.6	158.198	4.197
5.	Delivered Supplies	1,463,916.2	242,442.9	165.613	4.394
6.	Total Supply Costs	6,070,349.6	923,631.9	152.155	4.037
	Transportation Costs				
7.1	TCPL - FT - Demand		137,888.7		
7.2	- FT - Commodity	1,742,663.8	9,443.0	5.419	0.144
7.3	- Parkway to CDA		3,238.4		
7.4	- STS - CDA		5,793.8		
7.5	- STS - EDA		4,687.0		
7.6	- Dawn to CDA		9,471.0		
7.7	- Dawn to EDA		22,582.0		
7.8	- Dawn to Iroquois		6,886.7		
7.9	Other Charges		0.0		
7.10	Nova Transmission		4,909.0		
7.11	Alliance Pipeline		40,546.8		
7.12	Vecto Pipeline		25,431.2		
7.	Total Transportation Costs		270,877.6		
8.	Total Before PGVA Adjustment	6,070,349.6	1,194,509.4	196.778	5.221
9.	PGVA Adjustment		0.0		
10.	Total Purchases & Receipt	6,070,349.6	1,194,509.4	196.778	5.221

Witness: D. Small

Summary of Gas Cost to Operations
Year ended December 31, 2011

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	6,070,349.6	1,194,509.4	196.778	5.221
11.	Storage Fluctuation	(122,245.3)	(24,055.1)		
12.	Commodity Cost to Operations	5,948,104.4	1,170,454.3	196.778	
13.	Storage and Transportation Costs		114,311.1		
14.	Gas Cost to Operations	5,948,104.4	1,284,765.4	215.996	5.731
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		119,715.6		
17.	Forecasted Gas Costs	5,948,104.4	1,404,481.0	236.122	6.265
	Regulatory Adjustments				
18.	NGV Vehicles		0.0		
19.	LRAM Adjustment		0.0		
20.	Accounting Adjustments		0.0		
21.	Forecasted Utility Gas Costs	5,948,104.4	1,404,481.0	236.122	6.265

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2011

Item #		
1.	Sendout To Operations	5,948,104.4
2.	T-Service Volumes	5,423,645.3
3.	Total Sendout	11,371,749.6
4.1	Residential Sales	3,356,349.2
4.2	Commercial Sales	2,007,072.9
4.3	Industrial Sales	366,841.2
4.4	T-Service	5,388,736.4
4.5	Rate 200 T-Service (Gazifere)	33,688.6
4.6	Rate 200 Sales (Gazifere)	123,704.1
4.7	Company Use	5,677.4
4.8	Unaccounted For (UAF)	64,211.4
4.9	Unbilled Forecast - Sales	484.7
4.10	Unbilled Forecast - T-Service	1,220.2
4.11	Lost and Unaccounted For (LUF)	23,763.5
4.12	LUF Capitalized	0.0
4.	Total System Requirements	11,371,749.7

Witness: D. Small

Summary of Storage & Transportion Costs
Fiscal 2011

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2011	Col. 2 Fiscal 2011 Storage Charges Recovered in Fiscal 2011	Col. 3 Fiscal 2010 Storage Charges Recovered in Fiscal 2011	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2011
	Storage				
1.1	Chatham D	132.3	72.7	61.3	134.0
1.2	Injection	121.3	37.2	74.1	111.2
1.3	Withdrawal	107.6	107.6	0.0	107.6
1.5	Market Based Storage	22,971.8	12,615.8	10,633.4	23,249.2
1.6	Other	1,304.5	1,304.5	(39.6)	1,264.9
1.	Total Storage	24,637.5	14,137.8	10,729.2	24,867.0
2.	Total Transportation	66,454.5	36,495.9	30,813.9	67,309.8
	Dehydration				
3.1	Demand	989.2	543.2	457.7	1,001.0
3.2	Commodity	188.0	188.0	0.0	188.0
3.	Total Dehydration	1,177.2	731.2	457.7	1,189.0
4.	Total Storage & Other Costs	92,269.2	51,364.9	42,000.8	93,365.7
	Fuel Costs				
5.1	Tecumseh	3,353.7	2,171.5	935.9	3,107.4
5.2	Union Storage	1,352.7	895.5	401.1	1,296.6
5.3	Union Transportation	16,642.4	16,074.5	466.9	16,541.4
5.	Total Fuel Costs	21,348.7	19,141.5	1,803.8	20,945.4
6.	Total Storage & Transportation	113,617.9	70,506.4	43,804.6	114,311.1
7.	Storage and Transportation Costs Charged to Gas Cost to Operations				114,311.1

Witness: D. Small

2011
Gas in Storage
Month End Balances and
Average of Monthly Averages

Item #		Rate Base 10^3m^3
Month end balances except @ January 1		
1.	January 1	1,407,809.4
2.	January	959,375.2
3.	February	561,052.7
4.	March	320,507.8
5.	April	292,008.6
6.	May	519,181.8
7.	June	857,461.4
8.	July	1,237,394.8
9.	August	1,618,453.2
10.	September	1,963,714.9
11.	October	2,130,349.2
12.	November	1,967,321.3
13.	December	1,530,054.8
14.	Average of Averages	1,157,979.4

Witness: D. Small

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

Line No.	Account Description	Account Acronym	Col. 1 Actual at August 31, 2011 Principal ($000's)	Col. 2 Actual at August 31, 2011 Interest ($000's)	Col. 3 Forecast at December 31, 2011 Principal ($000's)	Col. 4 Forecast at December 31, 2011 Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2011 DSMVA	(5,641.3)	(25.7)	1,366.4	(27.5)
2.	Demand Side Management V/A	2010 DSMVA	(2,717.1)	(70.3)	(2,717.1)	(83.5)
3.	Demand Side Management V/A	2009 DSMVA	1,165.1	15.8	-	-
4.	Lost Revenue Adjustment Mechanism	2009 LRAM	(45.7)	(0.4)	-	-
5.	Shared Savings Mechanism V/A	2009 SSMVA	5,364.2	52.6	-	-
6.	Class Action Suit D/A	2011 CASDA	9,419.1	875.6	4,709.6	437.8 [1]
7.	Deferred Rebate Account	2010 DRA	(2,355.4)	(5.0)	-	-
8.	Gas Distribution Access Rule Costs D/A	2011 GDARCDA	90.8	0.4	571.8	0.9 [2]
9.	Gas Distribution Access Rule Costs D/A	2010 GDARCDA	132.7	1.9	-	- [2]
10.	Ontario Hearing Costs V/A	2010 OHCVA	85.0	0.9	-	-
11.	Manufactured Gas Plant D/A	2011 MGPDA	250.7	14.9	370.7	16.3
12.	Unbundled Rate Implementation Cost D/A	2011 URICDA	97.6	0.4	146.4	0.9
13.	Unbundled Rate Implementation Cost D/A	2010 URICDA	144.1	1.6	-	-
14.	Open Bill Service D/A	2011 OBSDA	292.3	16.5	175.4	0.6
15.	Open Bill Access V/A	2011 OBAVA	264.8	9.5	158.8	0.7
16.	Municipal Permit Fees D/A	2011 MPFDA	-	-	1,100.0	- [2]
17.	Municipal Permit Fees D/A	2010 MPFDA	901.6	-	-	- [2]
18.	Average Use True-Up V/A	2010 AUTUVA	(2,145.2)	(21.0)	-	-
19.	Tax Rate and Rule Change V/A	2011 TRRCVA	(800.0)	-	(1,200.0)	(4.6)
20.	Tax Rate and Rule Change V/A	2010 TRRCVA	516.1	5.7	-	-
21.	Earnings Sharing Mechanism D/A	2010 ESMDA	(17,350.0)	(173.3)	-	-
22.	Mean Daily Volume Mechanism D/A	2011 MDVMDA	2,071.1	8.4	3,039.1	20.0 [2]
23.	Mean Daily Volume Mechanism D/A	2010 MDVMDA	1,280.4	12.5	1,280.4	18.9 [2]
24.	Mean Daily Volume Mechanism D/A	2009 MDVMDA	42.4	0.4	42.4	0.8 [2]
25.	IFRS Transition Costs D/A	2010 IFRSTCDA	2,080.6	30.5	-	-
26.	Electric Program Earnings Sharing D/A	2011 EPESDA	-	-	(386.7)	-
27.	Ex-Franchise Third Party Billing Services D/A	2011 EFTPBSDA	-	-	(193.3)	-
28.	Ex-Franchise Third Party Billing Services D/A	2010 EFTPBSDA	(251.9)	(2.5)	-	-
29.	Total non commodity related accounts		(7,108.0)	749.4	8,463.9	381.3
	Commodity Related Accounts					
30.	Purchased Gas V/A	2011 PGVA	(36,418.3)	(819.0)	-	- [3]
31.	Transactional Services D/A	2011 TSDA	(2,149.0)	(1.1)	(3,620.8)	(15.1)
32.	Transactional Services D/A	2010 TSDA	(7,264.5)	(82.1)	-	-
33.	Unaccounted for Gas V/A	2011 UAFVA	(511.9)	(4.4)	(511.9)	(6.8)
34.	Unaccounted for Gas V/A	2010 UAFVA	8,729.4	85.5	-	-
35.	Storage and Transportation D/A	2011 S&TDA	(530.4)	(2.0)	(900.0)	(5.0)
36.	Storage and Transportation D/A	2010 S&TDA	(531.8)	(5.6)	-	-
37.	Total commodity related accounts		(38,676.5)	(828.7)	(5,032.7)	(26.9)
38.	Total Deferral and Variance Accounts		(45,784.5)	(79.3)	3,431.2	354.4

Notes:

1. This is the projected CASDA balance at the end of 2011. In EB-2007-0731 the Board approved the clearance of the CASDA over 5 years. The first, or 2008 installment was approved by the Board in EB-2007-0615 and cleared in July and August 2008. The second, or 2009 installment was approved in EB-2009-0055 and cleared in April and May 2010. The third, or 2010 installment was approved in EB-2010-0042 and cleared in January 2011. The fourth, or 2011 installment was approved in EB-2011-0008 and will be cleared in October 2011. The December 2011 balance therefore represents approximately one fifth, and the final installment of the total approved for clearance.

2. The balances in the 2010/11 GDARCDA and MPFDA accounts, as well as the 2009/10/11 MDVMDA's, are annual expenditures (capital and O&M). Due to the capital component of these expenditures, the company has or will request the clearance of associated annual revenue requirements.

3. The PGVA is now cleared through a rolling twelve month forward looking mechanism as approved by the Board within the EB-2008-0106 proceeding. As such, any projected PGVA balance is no longer required or meaningful.

Witnesses: K. Culbert
A. Kacicnik
D. Small

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNTS
FOR FUTURE CLEARANCE

Line No.	Account Description	Account Acronym	Col. 1 Accounts approved in EB-2011-0008 for clearance in October 2011 Principal ($000's)	Col. 2 Accounts approved in EB-2011-0008 for clearance in October 2011 Interest ($000's)	Col. 3 Current estimate of accounts to be cleared commencing July 1, 2012 Principal ($000's)	Col. 4 Current estimate of accounts to be cleared commencing July 1, 2012 Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2010 DSMVA	-	-	(2,717.1)	(103.3)
2.	Demand Side Management V/A	2009 DSMVA	1,165.1	17.1	-	-
3.	Lost Revenue Adjustment Mechanism	2009 LRAM	(45.7)	(0.6)	-	-
4.	Shared Savings Mechanism V/A	2009 SSMVA	5,364.2	59.2	-	-
5.	Class Action Suit D/A	2011/12 CASDA	4,709.5	472.4 [1]	4,709.6	472.6 [1]
6.	Deferred Rebate Account	2010 DRA	(2,387.1)	(7.9)	-	-
7.	Gas Distribution Access Rule Costs D/A	2011 GDARCDA	-	-	-	- [2]
8.	Gas Distribution Access Rule Costs D/A	2010 GDARCDA	2,904.4	- [3]	-	-
9.	Ontario Hearing Costs V/A	2010 OHCVA	92.1	1.0	-	-
10.	Unbundled Rate Implementation Cost D/A	2011 URICDA	-	-	146.4	2.1
11.	Unbundled Rate Implementation Cost D/A	2010 URICDA	144.1	1.9	-	-
12.	Open Bill Service D/A	2011/12 OBSDA	87.7	8.5	87.7	0.9
13.	Open Bill Access V/A	2011/12 OBAVA	79.4	4.9	79.4	0.9
14.	Municipal Permit Fees D/A	2011 MPFDA	-	-	-	- [2]
15.	Municipal Permit Fees D/A	2010 MPFDA	306.3	- [3]	-	-
16.	Average Use True-Up V/A	2010 AUTUVA	(2,145.2)	(23.6)	-	-
17.	Tax Rate and Rule Change V/A	2011 TRRCVA	-	-	(1,200.0)	(13.6)
18.	Tax Rate and Rule Change V/A	2010 TRRCVA	516.1	6.3	-	-
19.	Earnings Sharing Mechanism D/A	2010 ESMDA	(17,350.0)	(194.7)	-	-
20.	Mean Daily Volume Mechanism D/A	2011 MDVMDA	-	-	-	- [2]
21.	Mean Daily Volume Mechanism D/A	2010 MDVMDA	-	-	-	- [2]
22.	Mean Daily Volume Mechanism D/A	2009 MDVMDA	-	-	-	- [2]
23.	IFRS Transition Costs D/A	2010 IFRSTCDA	2,080.6	32.9	-	-
24.	Electric Program Earnings Sharing D/A	2011 EPESDA	-	-	(386.7)	(3.0)
25.	Ex-Franchise Third Party Billing Services D/A	2011 EFTPBSDA	-	-	(193.3)	(1.2)
26.	Ex-Franchise Third Party Billing Services D/A	2010 EFTPBSDA	(251.9)	(2.8)	-	-
27.	Total non commodity related accounts		(4,730.4)	374.6	526.0	355.4
	Commodity Related Accounts					
28.	Transactional Services D/A	2011 TSDA	-	-	(3,620.8)	(41.5)
29.	Transactional Services D/A	2010 TSDA	(7,264.5)	(91.0)	-	-
30.	Unaccounted for Gas V/A	2011 UAFVA	-	-	(511.9)	(10.4)
31.	Unaccounted for Gas V/A	2010 UAFVA	8,729.4	96.3	-	-
32.	Storage and Transportation D/A	2011 S&TDA	-	-	(900.0)	(11.6)
33.	Storage and Transportation D/A	2010 S&TDA	(531.8)	(6.4)	-	-
34.	Total commodity related accounts		933.1	(1.1)	(5,032.7)	(63.5)
35.	Total Deferral and Variance Accounts		(3,797.3)	373.5	(4,506.7)	291.9

Notes:

1. The balances shown in the 2011/12 CASDA account represent the fourth (2011) and fifth (2012) installments of the balance approved for recovery over five years (2008-2012) in EB-2007-0731. The fourth (2011) installment was approved for clearance in October 2011 along with other 2010 deferral accounts. EGD will be requesting clearance of the final 2012 installment within the 2011 ESM review application and proceeding.

2. The amounts which will be requested for clearance in relation to the 2011 GDARCDA, 2011 MPFDA, and 2009/10/11 MDVMDA's will be determined within a revenue requirement calculation as referenced on page 1 of this exhibit. EGD will bring these amounts forward within the presentation of deferral and variance accounts within the 2011 ESM review application and proceeding.

3. The balances in the 2010 GDARCDA and MPFDA accounts are the revenue requirements approved for clearance in the EB-2011-0008 proceeding.

Witnesses: K. Culbert
A. Kacicnik
D. Small

C – OTHER ITEMS REQUIRING SPECIFIC APPROVAL

DEFERRAL AND VARIANCE ACCOUNTS

A) EB-2011-0008 Clearance of Approved Deferral and Variance Accounts

1. In the decision for the EB-2011-0008 proceeding, the Board approved the clearance of certain Deferral and Variance Accounts (“DA” and “VA”) to occur at October 1, 2011. The following is the list of accounts approved for clearance:

Gas related DA’s and VA’s:

1. 2010 Transactional Services DA (“TSDA”),
2. 2010 Unaccounted for Gas VA (“UAFVA”), and
3. 2010 Storage and Transportation DA (“S&TDA”).

Non-Gas related DA’s and VA’s:

4. 2011 Class Action Suit DA (“CASDA”),
5. 2010 Deferred Rebate Account (“DRA”),
6. 2010 Gas Distribution Access Rule Costs DA (“GDARCDA”),
7. 2010 Ontario Hearing Costs VA (“OHCVA”),
8. 2010 Unbundled Rate Implementation Cost DA (“URICDA”),
9. 2011 Open Bill Service DA (“OBSDA”),
10. 2011 Open Bill Access VA (“OBAVA”),
11. 2010 Municipal Permit Fees DA (“MPFDA”),
12. 2010 Average Use True-Up VA (“AUTUVA”),
13. 2010 Tax Rate and Rule Change VA (“TRRCVA”),
14. 2010 Earnings Sharing Mechanism DA (“ESMDA”),
15. 2010 IFRS Transition Costs DA (“IFRSTCDA”),
16. 2010 Ex-Franchise Third Party Billing Services DA (“EFTPBSDA”).

Witnesses: K. Culbert
A. Kacicnik
D. Small

DSM related DA's and VA's:

17. 2009 Demand-Side Management VA ("DSMVA"),
18. 2009 Lost Revenue Adjustment Mechanism ("LRAM"), and
19. 2009 Shared Savings Mechanism VA ("SSMVA").

B) <u>Outstanding 2009, 2010, and 2011 Test Year Deferral and Variance Accounts</u>

4. The following list identifies outstanding 2009, 2010, and 2011 deferral and variance accounts, which were approved by the Board for continuation or establishment for their respective test years, but have not yet been approved for clearance. The listing has been divided into three groupings - Gas related, Non-Gas related, and DSM related:

Gas related DA's and VA's:

1. 2011 Purchased Gas VA ("PGVA"),
2. 2011 Transactional Services DA ("TSDA"),
3. 2011 Unaccounted for Gas VA ("UAFVA"),
4. 2011 Storage and Transportation DA ("S&TDA"), and

Non-Gas related DA's and VA's:

5. 2011 Carbon Dioxide Offset Credits DA ("CDOCDA"),
6. 2011 Class Action Suit DA ("CASDA"),
7. 2011 Deferred Rebate Account ("DRA"),
8. 2011 Electric Program Earnings Sharing DA ("EPESDA"),
9. 2011 Gas Distribution Access Rule Costs DA ("GDARCDA")
10. 2011 Manufactured Gas Plant DA ("MGPDA"),
11. 2011 Municipal Permit Fees DA ("MPFDA"),
12. 2011 Ontario Hearing Costs VA ("OHCVA"),

13. 2011 Unbundled Rate Implementation Cost DA (“URICDA”),
14. 2011 Unbundled Rates Customer Migration VA (“URCMVA”),
15. 2011 Average Use True-Up VA (“AUTUVA”),
16. 2011 Tax Rate and Rule Change VA (“TRRCVA”),
17. 2011 Earnings Sharing Mechanism DA (ESMDA”),
18. 2011 International Financial Reporting Standards Transition Costs DA (“IFRSTCDA”),
19. 2011 Open Bill Service DA (“OBSDA”),
20. 2011 Open Bill Access VA (“OBAVA”),
21. 2011 Open Bill Revenue VA (“OBRVA”),
22. 2011 Ex-Franchise Third Party Billing Services DA (“EFTPBSDA”),
23. 2009 Mean Daily Volume Mechanism Deferral Account (“MDVMDA”),
24. 2010 Mean Daily Volume Mechanism Deferral Account (“MDVMDA”),
25. 2011 Mean Daily Volume Mechanism Deferral Account (“MDVMDA”), and

DSM related DA’s and VA’s:

26. 2010 Demand Side Management VA (“DSMVA”),
27. 2011 Demand Side Management VA (“DSMVA”),
28. 2010 Lost Revenue Adjustment Mechanism (“LRAM”),
29. 2011 Lost Revenue Adjustment Mechanism (“LRAM”),
30. 2010 Shared Saving Mechanism VA (“SSMVA”),
31. 2011 Shared Saving Mechanism VA (“SSMVA”).

C) Clearance of Deferral and Variance Accounts July 1, 2012

5. The establishment of the above 2010 & 2011 related DA’s and VA’s was approved by the Board in various earlier proceedings. Within the list of the above accounts,

the Board has already approved the clearance of a certain amount within the 2011 CASDA.

6. Of the remaining accounts, not all are currently being requested for clearance:
   - The balance in the 2011 Manufactured Gas Plant DA (“MGPDA”) will be transferred into a 2012 MGPDA in order to bring forward the accumulated balance in the 2011 account. This is an ongoing matter which to date is unresolved and as a result the Company is not proposing to clear any balance related to the Manufactured Gas Plant issue at this time.
   - The following DSM-related variance accounts are expected to be the subject of clearing and/or discontinuation (if the balance is zero), subsequent to the Board’s approval of DSM audit results, the timing of which is not currently known and therefore it is unknown whether clearance could commence on July 1, 2012.
     - 2011 Demand-Side Management VA (“DSMVA”),
     - 2011 Lost Revenue Adjustment Mechanism (“LRAM”),
     - 2011 Shared Savings Mechanism VA (“SSMVA”).

7. Within the 2011 EB-2010-0146 proceeding, the Company provided and the Board approved, updated tax savings and sharing calculations for the years 2009 through 2012. As a result of the implementation of the Harmonized Sales Tax (“HST”) on July 1, 2010, the EB-2010-0146 approved tax savings and sharing agreement required a further update, which was provided and approved in EB-2011-0008, to account for the effects of the new HST. The updated amount to be credited within the 2011 TRRCVA could not be incorporated into 2011 due to timing. Evidence at Exhibit C, Tab 1, Schedule 4, explains the $1.2 million being requested for clearance through the 2011 TRRCVA. The Company is requesting clearance of the 2011 TRRCVA account to be cleared to ratepayers commencing July 1, 2012.

Witnesses: K. Culbert
A. Kacicnik
D. Small

8. 2011 Class Action Suit Deferral Account Treatment
    - The Class Action Suit Deferral Account ("CASDA") was approved within the EB-2007-0731 proceeding for recovery over a five year period commencing in 2008, the uncleared balance in the account at the end of each fiscal year is to be brought forward into a next year like named deferral account until completion of the clearance process. Therefore, in July 2012 the Company will clear approximately one half of the remaining uncleared balance in the CASDA.

9. Open Bill Service DA and Open Bill Access VA Treatment
    - The treatment of the recovery of the existing Open Bill Service DA and Open Bill Access VA was approved within the EB-2008-0043 proceeding. The balances in the OBSDA and OBAVA will be recovered over a three year period commencing in 2010. The uncleared balances in the accounts at the end of each fiscal year are to be brought forward into a next year like named account until completion of the clearance process. Therefore as the first year of clearance commenced in April, 2010, in July 2012 the Company will clear the remaining balance in the 2011 OBSDA and 2011 OBAVA.

10. A summary of the actual DA and VA balances planned to be cleared commencing in at July 1, 2012, is included at Exhibit B, Tab 5, Schedule 1, pages 1 and 2.

11. The balances accumulated at the end of December, 2011 and approved to be cleared commencing July 1, 2012, will be included within the Company's July 1, 2012 QRAM filing.

Witnesses: K. Culbert
A. Kacicnik
D. Small

D) Proposed 2012 Deferral and Variance Accounts

12. The Company has reviewed the existing, and potential requirement for, deferral or variance accounts during the IR period and the following is the current list proposed by the Company for the 2012 fiscal year, divided into three groupings - Gas related, Non-Gas related, and DSM related:

Gas related DA's and VA's

1. 2012 Purchased Gas VA ("PGVA"),
2. 2012 Transactional Services DA ("TSDA"),
3. 2012 Unaccounted for Gas VA ("UAFVA"),
4. 2012 Storage and Transportation DA ("S&TDA"), and

Non-Gas related DA's and VA's

5. 2012 Carbon Dioxide Offset Credits DA ("CDOCDA"),
6. 2012 Class Action Suit DA ("CASDA"),
7. 2012 Deferred Rebate Account ("DRA"),
8. 2012 Electric Program Earnings Sharing DA ("EPESDA"),
9. 2012 Gas Distribution Access Rule Costs DA ("GDARCDA"),
10. 2012 Manufactured Gas Plant DA ("MGPDA"),
11. 2012 Municipal Permit Fees DA ("MPFDA"),
12. 2012 Ontario Hearing Costs VA ("OHCVA"),
13. 2012 Unbundled Rate Implementation Cost DA ("URICDA"),
14. 2012 Unbundled Rates Customer Migration VA ("URCMVA"),
15. 2012 Average Use True-Up VA ("AUTUVA"),
16. 2012 Tax Rate and Rule Change VA ("TRRCVA)
17. 2012 Earnings Sharing Mechanism DA ("ESMDA"),
18. 2012 Open Bill Service DA ("OBSDA"),

Witnesses: K. Culbert
A. Kacicnik
D. Small

19. 2012 Open Bill Access VA ("OBAVA")
20. 2012 Open Bill Revenue VA ("OBRVA")
21. 2012 Ex-Franchise Third Party Billing Services DA ("EFTPBSDA"),
22. 2012 Mean Daily Volume Mechanism DA ("MDVMDA"),
23. 2012 Pension Funding Costs VA ("PFCVA"),
24. 2012 Cross Bores Costs Variance Account ("CBCVA"), and
25. 2012 Transition Impact of Accounting Changes Deferral Account ("TIACDA")

DSM related DA's and VA's

26. 2012 Demand Side Management VA ("DSMVA"),
27. 2012 Lost Revenue Adjustment Mechanism ("LRAM"),
28. 2012 Demand Side Management Incentive DA ("DSMIDA").

13. All 2012 deferral and variance accounts requested to continue over from their approval in 2011 or prior will continue to be determined/calculated in the same manner as previously established. All other accounts being requested have descriptions as to their establishment and calculations in section E) below. Descriptions of the accounts will form part of the Company's draft rate order submission.

E) <u>New Deferral or Variance Accounts</u>

14. As outlined in evidence at Exhibit B, Tab 2, Schedule 5, EGD is requesting a pension funding Z factor to recover $17.7 million in fiscal 2012 rates and is also requesting a pension funding variance account in relation to this amount being requested for recovery, as explained in evidence at Exhibit C, Tab 1, Schedule 2.

Witnesses: K. Culbert
A. Kacicnik
D. Small

15. As outlined in evidence at Exhibit B, Tab 2, Schedule 6, EGD is requesting a cross bores-sewer lateral Z factor to recover \$3.8 million in fiscal 2012 and is also requesting a cross bore costs variance account in relation to this amount being requested for recovery, as explained in evidence at Exhibit C, Tab 1, Schedule 3.

16. As outlined in evidence at Exhibit C, Tab 1, Schedule 5, EGD is requesting to establish a transition impact of accounting changes deferral account.

Witnesses: K. Culbert
A. Kacicnik
D. Small

PENSION FUNDING COST VARIANCE ACCOUNT

1. The Company filed evidence at Exhibit B, Tab 2, Schedule 5, Z Factor Pension Funding Requirement explaining the request of a Z factor in relation to its pension funding position.

2. The Company is requesting $17.7 million of pension funding requirement to be included within the IR revenue determination for recovery within rates in 2012. The amount is based upon an estimate of a December 31, 2011 annual cost certificate of the pension fund and potential pension funding obligations.

3. In conjunction with this request the Company is also proposing a 2012 variance account treatment around the amount. The reason for this is that the actual December 31, 2011 annual cost certificate and funding requirement will not be available until February 2012 at the earliest. The variance account would capture the difference between the amount being recovered within rates and the actual funding requirement, with the difference being cleared to ratepayers along with all other deferral and variance accounts.

4. This treatment will ensure that ratepayers are paying no more than the actual cost of the required funding. Please refer to Exhibit B, Tab 2, Schedule 5, Z Factor Pension Funding Requirement for further details and explanation of the Company's proposal.

Witnesses: K. Culbert
S. Kancharla
A. Patel

CROSS BORE COSTS VARIANCE ACCOUNT

1. The Company filed evidence at Exhibit B, Tab 2, Schedule 6, titled “Z Factor Request Related to Cross Bores/Sewer Laterals” explaining the request of a Z factor in relation to its costs and revenue requirement associated with its Cross Bore Action Plan, which is mandated by the TSSA.

2. The Company is requesting $3.8 million to be included within the IR revenue determination for recovery within rates in 2012.

3. Given the timing and the potential variability associated with the actual costs and revenue requirement associated with this item, Enbridge proposes that the Z factor for cross bore costs should be coupled with a 2012 Cross Bore Costs Variance Account.

4. Once the 2012 costs and associated revenue requirement amount are known, then any variance from the forecast revenue requirement amount of $3.8 million will be transferred to this variance account for future refund to or collection from ratepayers. This process will ensure that the net recovery in rates is fully aligned with the costs ultimately incurred by Enbridge.

Witnesses: C. Clark
K. Culbert
L. Lawler

TAX RATE AND RULE CHANGE VARIANCE ACCOUNT

1. Within the 2011, EB-2011-0008 proceeding, the Company filed evidence and an updated summary of forecast tax savings and sharing amounts at Exhibit C, Tab 1, Schedule 4. As explained in that evidence, the forecast tax savings and sharing amounts were updated to take account of the impact of the implementation of the Harmonized Sales Tax ("HST") which was implemented on July 1st, 2010. Within the EB-2011-0008 Rate Order, the Board approved the Settlement Agreement wherein Exhibit N1, Tab 1, Schedule 1, pages 11 and 15, an analysis of the impact of the HST implementation and its impact within the forecast tax savings and sharing amounts, was agreed to by parties to that proceeding.

2. The Company has filed at page 2 of this evidence, a copy of a table summarizing the updated forecast tax savings and sharing amounts which were filed at page 3 of the previous proceedings evidence outlined above. The updated amount to be credited within the 2011 TRRCVA is $1.2 million (Line 65, Column 4, page 2), which due to timing could not be incorporated into 2011 rates. For 2012, the Company will include an incremental credit, inclusive of the $1.2 million in the 2011 TRRCVA, in the amount of $4.58 million (Line 66, Column 5, page 2) as an adjustment in the development of the 2012 Incentive Revenue formula, which will then reflect the cumulative impact of tax savings and sharing.

Witness: K. Culbert

Table 1

Updated Summary - Sharing of Tax Change Forecast Amounts

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

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
		2008	**2009**	**2010**	**2011**	**2012**	
	<u>Tax Related Amounts Forecast from CCA Rate Changes</u> **($ Millions)**						
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45/50) - Opening UCC Balance	1.54	2.24	1.14	0.51	1.64	
6.	New purchases (2007 Board Approved additions) - **with update for new Class 52**	2.13	2.13	2.13	2.13	2.13	
7.	**Re-grouping of amounts eligible for Class 52 (included at line 11)**	-	(1.95)	(2.13)	(0.18)	-	
8.	Capital Cost Allowance (CCA) at 55% -2007 Federal Budget tax rule CCA rate	1.43	1.28	0.63	0.82	1.49	
9.	Closing Undepreciated Capital Cost (UCC)	2.24	1.14	0.51	1.64	2.28	
10.	Computer Equipment (**New Class 52**) - Opening UCC Balance	-	-	-	-	-	
11.	New purchases (2007 Board Approved additions) - **with update for new Class 52**	-	1.95	2.13	0.18	-	
12.	Capital Cost Allowance (CCA) at 100% -2007 Federal Budget tax rule CCA rate	-	1.95	2.13	0.18	-	
13.	Closing Undepreciated Capital Cost (UCC)	-	-	-	-	-	
14.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.76	687.71	898.86	1101.57	
15.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
16.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
17.	Closing Undepreciated Capital Cost (UCC)	467.76	687.71	898.86	1101.57	1296.16	
18.	Distribution Assets (Class 51) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
19.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
20.	Capital Cost Allowance (CCA) at 6% -2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
21.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
22.	CCA Difference	7.27	12.82	15.85	17.29	20.67	
23.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	31.00%	28.25%	26.25%	
24.	Tax Impact	2.44	4.23	4.91	4.89	5.43	
25.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.65	6.31	7.12	6.81	7.36	31.26
26.	Incremental Amount	3.65	2.66	0.81	(0.31)	0.55	
27.	**50% of the Amount to Reduce Rates**	**$1.83**	**$1.33**	**$0.40**	**-$0.16**	**$0.28**	
	<u>Tax Related Amounts Forecast from Income Tax Rate Changes</u>						
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**	
	<u>Capital Tax Related Amounts Forecast from Capital Tax Rate Changes</u>						
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**	
	<u>Capital Tax Related Amounts Forecast from Taxable Capital Changes</u>						
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**	
	<u>Revenue Requirement Amounts Forecast from HST Change Impacts</u>						
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)			

TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL ACCOUNT

1. Enbridge Gas Distribution Inc. (“EGD”) requests approval to establish a 2012 Transition Impact of Accounting Changes Deferral Account (“TIACDA”) to recognize and record the financial impacts which will occur in 2012 in relation to EGD’s required transition away from current Canadian Generally Accepted Accounting Principles (“CGAAP”).

2. In accordance with the requirements of the Accounting Standards Board of the Canadian Institute of Chartered Accountants, EGD is obligated to move away from CGAAP beginning January 1, 2012. As a result of this transition a set of financial impacts to EGD will result from the mandatory requirement of having to report under an accounting standard different from CGAAP.

3. Under CGAAP, EGD recorded post employment benefits on the balance sheet representing the funded status plus the unamortized transitional asset less unamortized net actuarial gains with a corresponding regulatory offset, in the expectation that such costs would be allowed recovery or inclusion in future rates. In the absence of CGAAP, EGD cannot record a regulatory offset resulting in the entire balance being written off to retained earnings. Without the ability to record a regulatory offset as was permitted within CGAAP, there will be a direct impact to earnings in the amount of the difference between a cash basis of accounting which EGD currently follows and an accrual basis of accounting required by EGD as of 2012.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

4. EGD's deferral account request is consistent with the OEB's EB-2009-0408, Addendum to Report of the Board[1]. Within the addendum at page 19, the Board in effect indicated that any utility that it regulates which is required to transition away from CGAAP, and which chooses to adopt/request an accounting standard for regulatory purposes other than modified IFRS ("MIFRS"), would be required to explain the use of that alternate accounting standard. The Board also indicated that a utility, in its first cost of service application following the adoption of a new accounting standard, must explain to the Board the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation.

5. EGD will explain all of the impacts as a result of transitioning away from CGAAP and adopting an alternate accounting standard in its 2013 rate application, its first cost of service application following the accounting standard transition, in accordance with the requirement laid out in the EB-2009-0408 Report of the Board. EGD is proposing the TIACDA to record the associated accounting impacts which occur in 2012 pending the Board's consideration of the explanation of the impacts within the 2013 rate application.

[1] EB-2009-0408 Addendum to Report of the Board, Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

D – 2010 ACTUAL RESULTS

2010 HISTORICAL RESULTS AND ASSOCIATED INFORMATION

1. The Company's Fiscal 2010 Historical Utility financial results and supporting customer, volumetric, revenue and cost information were filed, reviewed and approved by the Board within the 2010 Earnings Sharing Mechanism proceeding, docket number EB-2011-0008.

SETTLEMENT AGREEMENT

FEBRUARY 4, 2008

TABLE OF CONTENTS

I. INTRODUCTION

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

II. SETTLEMENT CONFERENCE

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

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

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

III. ISSUES

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

IV. SETTLEMENT CATEGORIES

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

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

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

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

V. PARAMETERS OF AGREEMENT

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

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

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

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

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

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

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

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

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

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

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

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

VI. OVERVIEW OF AGREEMENT

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

1. establish incentives for sustainable efficiency improvements that benefit customers and shareholders;

2. ensure appropriate quality of service for customers; and

3. create an environment that is conducive to investment, to the benefit of customers and shareholders.

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

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

VII. ISSUE-BY-ISSUE SETTLEMENTS

1 MULTI-YEAR INCENTIVE RATEMAKING FRAMEWORK

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

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

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

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

2 INFLATION FACTOR

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

2.1.1 Which macroeconomic or industry specific index should be used?

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

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

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

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

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

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

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

2.3 How often should the Board update the inflation factor?

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

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

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

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

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

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

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

3 X Factor

3.1 How should the X factor be determined?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.2 What are the appropriate components of an X factor?

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

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

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

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

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

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

4 AVERAGE USE FACTOR

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5 Y FACTOR

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

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

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

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

(iii) upstream gas costs;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.2 What are the criteria for disposition?

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

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

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

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

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

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

6 Z FACTOR

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

- **Complete Settlement:**

Z-Factor Criteria

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

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

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

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

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

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

ROE Methodology

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

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

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

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

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

NGEIR

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

Changes in Tax Rules and Rates

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

7 NATURAL GAS ELECTRICITY INTERFACE REVIEW (NGEIR) DECISIONS

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

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

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

8 TERM OF THE PLAN

8.1 What is the appropriate plan term for each utility?

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

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

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

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

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

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

9 OFF-RAMPS

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

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

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

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

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

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

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

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

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

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

9.2 If so, what should be the parameters?

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

10 Earning Sharing Mechanism (ESM)

10.1 Should an ESM be included in the IR plan?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

10.2 If so, what should be the parameters?

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

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

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

11 REPORTING REQUIREMENTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

12 RATE-SETTING PROCESS

12.1 Annual Adjustment

12.1.1 What should be the information requirements?

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

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

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

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

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

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

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

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

(viii) a draft rate order; and

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

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

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

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

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

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

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

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

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

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

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

12.2 New Energy Services

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

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

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

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

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

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

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

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

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

12.3 Changes in Rate Design

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

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

Changes to Monthly Customer Charges

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

The Parties also agree that:

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

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

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

Changes to Rate 135

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

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

Contract Demand Levels

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

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

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

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

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

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

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

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

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

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

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

12.4 Non-Energy Services

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

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

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

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

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

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

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

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

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

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

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

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

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

13 REBASING

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

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

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

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

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

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

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

14 ADJUSTMENTS TO BASE YEAR REVENUE REQUIREMENTS AND/OR RATES

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

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

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

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

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

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

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

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

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

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

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

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

14.2 If so, how should these adjustments be made?

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

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

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

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

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

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

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

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

D-7-1	Application dated June 29, 2007

List of Issues

Appendix A of Procedural Order No. 4

1 Multi-Year Incentive Ratemaking Framework

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

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

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

2 Inflation Factor

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

2.1.1 Which macroeconomic or industry specific index should be used?

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

2.3 How often should the Board update the inflation index?

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

3 X Factor

3.1 How should the X factor be determined?

3.2 What are the appropriate components of an X factor?

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

4 Average Use Factor

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

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

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

5 Y Factor

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

5.2 What are the criteria for disposition?

6 Z Factor

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

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

7 Natural Gas Electricity Interface Review (NGEIR) Decisions

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

8 Term of the Plan

8.1 What is the appropriate plan term for each utility?

9 Off-Ramps

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

9.2 If so, what should be the parameters?

10 Earning Sharing Mechanism (ESM)

10.1 Should an ESM be included in the IR plan?

10.2 If so, what should be the parameters?

11 Reporting Requirements

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

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

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

12 Rate-Setting Process

12.1 Adjustment Formula

12.1.1 What should be the information requirements?

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

12.2 New Energy Services

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

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

12.3 Changes in Rate Design

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

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

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

12.4 Non-Energy Services

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

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

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

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

13 Rebasing

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

14 Adjustments to Base Year Revenue Requirements and/or Rates

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

14.2 If so, how should these adjustments be made?

Deferral and Variance Accounts

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

Gas related DA's and VA's

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

Non-gas related DA's and VA's

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

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

DSM related DA's and VA's

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

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

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

Estimated Distribution Revenue Per Customer Cap

Determination (2008-2012)

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

Process

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Summary - Sharing of Tax Change Forecast Amounts

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

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

2008

Col. 1 ITEM NO.	Col. 2 DESCRIPTION	Col. 3 TOTAL	Col. 4 RATE 1	Col. 5 RATE 6	Col. 6 RATE 9	Col. 7 RATE 100	Col. 8 RATE 110	Col. 9 RATE 115	Col. 10 RATE 125	Col. 11 RATE 135	Col. 12 RATE 145	Col. 13 RATE 170	Col. 14 RATE 200	Col. 15 RATE 300 Firm	Col. 16 RATE 300 Int	Col. 17 DIRECT PURCHASE
	Total DRR	934.8	627.1	244.3	1.2	25.5	10.4	7.9	3.5	0.7	4.6	5.1	2.1	0.3	0.2	1.6
	Y Factor: Other															
1.1	2008 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2008 Board Approved Amount	23.1	11.2	5.8	-	2.3	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2008	89.2	81.7	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2008 Leave to Construct	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	
	Total Y-Factor Revenue requirement	155.3	113.0	30.6	0.0	4.6	1.3	1.5	(0.0)	0.1	1.1	2.5	0.5	0.0	0.0	-
	Total DRR minus Y-Factor	779.5	514.0	213.6	1.2	20.9	9.2	6.4	3.5	0.6	3.5	2.6	1.6	0.3	0.2	1.6

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

2009

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

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

2010

Col. 1 ITEM NO.	Col. 2 DESCRIPTION	Col. 3 TOTAL	Col. 4 RATE 1	Col. 5 RATE 6	Col. 6 RATE 9	Col. 7 RATE 100	Col. 8 RATE 110	Col. 9 RATE 115	Col. 10 RATE 125	Col. 11 RATE 135	Col. 12 RATE 145	Col. 13 RATE 170	Col. 14 RATE 200	Col. 15 RATE 300 Firm	Col. 16 RATE 300 Int	Col. 17 DIRECT PURCHASE
	Total DRR	986.0	659.8	256.9	1.3	27.0	10.9	8.2	6.4	0.7	4.8	5.2	2.3	0.3	0.2	1.6
	Y Factor: Other															
1.1	2010 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2010	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2010	89.2	82.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2010 Leave to Construct	3.0	1.4	1.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	159.6	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	-
	Total DRR minus Y-Factor	826.4	544.3	225.1	1.3	22.1	9.6	6.7	6.2	0.6	3.7	2.7	1.7	0.3	0.2	1.6

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

2011

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	Total DRR	1,006.4	673.5	262.2	1.3	27.6	11.2	8.4	6.4	0.7	4.9	5.3	2.3	0.4	0.2	1.6
	Y Factor: Other															
1.1	2011 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2011	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2011	89.2	82.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2011 Leave to Construct	3.0	1.3	1.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	159.5	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	-
	Total DRR minus Y-Factor	846.8	558.1	230.4	1.3	22.6	9.8	6.8	6.3	0.6	3.8	2.8	1.7	0.4	0.2	1.6

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

2012

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

Estimated Rate Impacts (2008-2012)

ESTIMATED 2008-2012 RATE IMPACTS

Rate Class	ADR 2008[1] T-Service Rate Impact	ADR 2009[2] T-Service Rate Impact	ADR 2010[3] T-Service Rate Impact	ADR 2011[4] T-Service Rate Impact	ADR 2012[5] T-Service Rate Impact
1	0.1%	2.1%	1.6%	1.5%	1.7%
6	0.0%	1.8%	1.3%	1.2%	1.4%
9	0.1%	0.8%	1.1%	1.2%	1.6%
100	0.1%	1.3%	1.0%	0.9%	0.9%
110	0.1%	1.1%	1.0%	0.9%	0.9%
115	0.1%	1.1%	0.8%	0.8%	0.8%
135	0.6%	0.9%	0.9%	0.9%	0.9%
145	0.2%	1.0%	0.9%	0.8%	0.8%
170	0.4%	1.0%	0.9%	0.9%	0.9%
200	0.4%	1.0%	0.9%	0.8%	1.0%
	ADR 2008 Distribution Rate Impact	ADR 2009 Distribution Rate Impact	ADR 2010 Distribution Rate Impact	ADR 2011 Distribution Rate Impact	ADR 2012 Distribution Rate Impact
125	0.0%	0.7%	0.7%	0.7%	0.7%
300	0.1%	0.9%	0.9%	0.9%	0.9%

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

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Estimated Bill Impacts (2008-2012)

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

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

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
BALANCES

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

Notes:

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

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

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

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

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

Witnesses: R. Bourke
K. Culbert

RETURN ON EQUITY

1. The purpose of this evidence is to provide the Return on Equity ("ROE") used for the calculation of earnings sharing, if any, for 2011 and 2012. The Company has calculated ROE for 2011 and 2012 using the methodology provided in the Board's "Draft Guidelines on a Formula-Based Return on Equity for Regulated Utilities".

2. In accordance with the Board's Decision in the Company's EB-2007-0615 rate case, earnings sharing will be calculated:

   > …if in any calendar year, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than 100 basis points over the amount calculated annually by the application of the Board's ROE Formula in any year of the IR Plan…

   Table 1 shows the calculation of ROE for 2011.

Table A1
Determination of ROE for 2011

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Yield on 10s 3 Months Out[a]	Yield 10s 12 Months Out[a]	Average 10s Yield	Average Spread (30s-10s)[b]	Long Bond Forecast	Difference in Long Bond Forecast	0.75xDifference (Rounded to 2 Decimal Places)	ROE (%)
		(Col. 1+Col. 2)/2		Col. 3+Col. 4	Col. 5-4.23	0.75xCol. 6	8.37+Col. 7
2.80	3.30	3.05	0.60	3.65	-0.58	-0.43	7.94

Notes:
2010 ROE: 8.37
2010 Long Canada Forecast: 4.23
[a] From Consensus Forecasts October 11, 2010
[b] From Financial Post

   Based on the October 2010 Consensus Forecasts publication and the data provided in the Financial Post, ROE for 2011 is 7.94%.

3. Data are currently not available for the calculation of ROE for 2012. It is expected that the data will be available by mid-October 2011, at which point ROE for 2012 will be calculated and attached as an appendix to this Exhibit.

Witness: S. Murray