EXHIBIT LIST

A – ADMINISTRATIVE

Exhibit	Tab	Schedule	Contents	Witness(es)
A	1	1	Exhibit List	R. Bourke
	2	1	Application	F. Cass
	3	1	Approvals Requested	R. Bourke
	4	1	Curriculum Vitae	R. Bourke
		2	Curriculum Vitae	R. Bourke
	5	1	Draft Issues List	R. Bourke

B – 2010 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	2010 Rate Adjustment Summary	R. Bourke
		2	2010 Revenue per Customer Cap Determination	I. Chan K. Culbert A. Kacicnik T. Ladanyi D. Small
		3	Inflation Factor	J. Denomy
		4	Customer Additions	J. Denomy S. Murray
		5	Gas Volume Budget	I. Chan T. Ladanyi
		6	Budget Degree Days	J. Denomy
		7	Average Use and Economic Assumptions	J. Denomy
	2	1	Y Factor Power Generation Projects	K. Culbert T. Ladanyi

EXHIBIT LIST

B – 2010 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION

Exhibit	Tab	Schedule	Contents	Witness(es)
B	2	2	Y Factor DSM Program	A. Mandyam P. Squires
		3	Not Used	
		4	Y Factor Green Energy Initiatives - Withdrawn	
		5	Y Factors – Other	K. Culbert D. Small
	3	1	Z Factor Pension Funding Commitment	J. Haberbusch N. Kishinchandani Mercers (consultant)
		2	Z Factor Related to Crossbores/Sewer Laterals	C. Clark L. Lawler
	4	1	2010 Proposed Rates	J. Collier A. Kacicnik M. Suarez
		2	Rate Schedules	J. Collier A. Kacicnik
		3	2009 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

EXHIBIT LIST

B – 2010 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION

Exhibit	Tab	Schedule	Contents	Witness(es)
B	4	7	Calculation of Gas Supply Charges by Rate Class	J. Collier A. Kacicnik
		8	Detailed Revenue Calculations	J. Collier A. Kacicnik
		9	Annual Bill Comparison EB-2009-0172 vs. EB-2009-0309	J. Collier A. Kacicnik
		10	Assignment of Revenue Requirement	M. Suarez A. Kacicnik
	5	1	Not Used	
	6	1	Summary of Gas Cost to Operations	D. Small
		2	Gas Cost Schedules	D. Small
	7	1	Deferral & Variance Accounts – Actual Balances	K. Culbert A. Kacicnik D. Small

C - OTHER ITEMS REQUIRING SPECIFIC APPROVAL

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	1	Deferral & Variance Accounts	K. Culbert A. Kacicnik D. Small
		2	Pension Funding Costs Variance Account	K. Culbert J. Haberbusch N. Kishinchandani
		3	Crossbores / Sewer Lateral Cost Variance Account	C. Clark K. Culbert L. Lawler

EXHIBIT LIST

C - OTHER ITEMS REQUIRING SPECIFIC APPROVAL

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	4	Update of Sharing of Tax Change Savings Forecast Amounts	K. Culbert
		5	Service Quality Requirements	T. Ferguson K. Lakatos-Hayward B. Visnjevac

D – 2008 ACTUAL RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	2008 Historical Year Review EB-2009-0055	K. Culbert

E – REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
E	1	1	Settlement Agreement – EB-2007-0615 dated February 4, 2008	R. Bourke T. Ladanyi
	2	1	Customer Care and CIS Settlement Template (the “True-Up” Template) – EB-2007-0615 Rate Order, Appendix F dated May 15, 2008	R. Bourke K. Culbert
	3	1	Return on Equity	J. Denomy M. Lister

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", or the "Company") is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting and storing natural gas within Ontario.

2. Enbridge hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 36 of the *Ontario Energy Board Act, 1998*, 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, 2010.

3. As of January 1, 2010, Enbridge will be entering the third 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. The Settlement Agreement provides for an annual rate adjustment process and, in that regard, states as follows:

> The Company shall file … 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 …

5. The Settlement Agreement also specifies information to be filed by Enbridge for the purposes of the annual rate adjustment process. The information to be filed by Enbridge includes a draft rate Order and a Rate Handbook, together with supporting documentation detailing how rates have been adjusted to reflect the application of the Adjustment Formula.

6. In its Decision and Order in Phase 2 of Enbridge's 2009 Rate Adjustment Application (EB-2008-0219), the Board adopted a refined timeline for the rate setting process for Enbridge's 2010 rate adjustment process, to allow for 2010 rates to be in place for January 1, 2010. The Board's Decision and Order approved an approach where Enbridge would file its Application by September 1st, to enable the Board to issue its Notice of Application shortly thereafter. Enbridge would then file its supporting evidence by October 1st.

7. Enbridge therefore 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, 2010;
>
> (ii) the approval of the Company's draft rate Order and Rate Handbook, subject to such changes, if any, that the Board may deem appropriate; and
>
> (iii) 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, 2010.

8. The Company 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.

9. The evidence in support of Enbridge's Application will be filed by October 1, 2009.

10. As a result of this Application, average rate increases will be approximately 5.0% 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 5.0%, or about $30 annually. As required by the Settlement Agreement (p. 31), Enbridge's filing in support of the Application will include detailed evidence explaining the rate increases.

11. The Company respectfully requests that the Board establish a process for the aspects of this Application referred to in paragraphs 7(i) and 7(ii), above (namely, the application of the Adjustment Formula for 2010 and approval of the draft rate Order and Rate Handbook), that is consistent with the timeline adopted in the Decision and Order in Phase 2 of Enbridge's 2009 Rate Adjustment Application (EB-2008-0219).

12. There are other issues to be determined in this proceeding, as referred to in paragraph 7(iii), above, that bear upon the Board's approval or fixing of just and reasonable rates, but that do not need to be decided in order for the Board to issue an Order regarding the application of the Adjustment Formula for 2010. It may be appropriate to consider such issues separately from those related to the Adjustment Formula.

13. These issues may include Enbridge's requests for the following:

a. A Z-factor to recover 2010 pension-related costs, which were not forecast or anticipated, as well as a related variance account.

b. A Z-factor to recover costs related to new construction and excavation standards, methods and approaches implemented to, among other things, reduce the incidence of crossbores and costs to identify and address existing crossbores, as well as a related variance account.

c. The division of the Y-factor related to demand side management (DSM) activities including a base-DSM amount, which includes a new program requested in the current EB-2009-0154 proceeding, and low-income funding comprised of low income DSM program costs and emergency funding both based on the Board's directions in EB-2008-0150.

d. The continuation for 2010 of the deferral and variance accounts set out in Appendix B to the Settlement Agreement.

e. The continuation for 2010 of certain deferral and variance accounts related to open bill activities and International Financial Reporting Standards (IFRS) costs that were not included in the Settlement Agreement, but which are anticipated to be approved in 2009.

f. Approval of a Y-factor and regulatory framework for the offering and provision of district energy and alternative or renewable energy activities and services by the regulated utility in future years.

14. It may be appropriate for the Board to implement a two-phase proceeding in order to accommodate the hearing of some or all of these other issues in a second phase, separate from those issues that are part of, or can be dealt with at the same time as, the Adjustment Formula.

15. 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 14, 2009 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: ______________________

APPROVALS REQUESTED

1. The Company has filed updated evidence in support of its determination of the 2010 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 2010 rate adjustment are located in the "B" series of exhibits. /u

2. The rate schedules filed at Exhibit B-4-2 are the culmination of the 2010 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, 2010.

3. The IR model approved by the Board for Enbridge is a Revenue per Customer Cap methodology which utilizes an index of historical inflation (GDP IPI FDD found at Exhibit B-1-3) 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 and Z factors included with this application.

5. Inherent in the request to approve the 2010 rate adjustment, are the 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-1-4);
ii) Gas Volume Budget (Exhibit B-1-5);
iii) Forecast of degree days (Exhibit B-1-6);
iv) Forecast of average use (Exhibit B-1-7);
v) Y factor Power Generation Projects (Exhibit B-2-1);
vi) Y factor DSM Program (Exhibit B-2-2);
vii) Y factor – Others (Exhibit B-2-5);
viii) Z factor Pension Funding Cost Recovery (Exhibit B-3-1);
ix) Z factor Crossbores/Sewer Laterals Initiative (Exhibit B-3-2); and
x) The 2010 adjustment using the Tax Rate and Rule Change VA ("TRRCVA" Exhibit C-1-4).

6. The Company is also requesting that the Board approve for the 2010 Test Year, the deferral and variance accounts as shown in evidence in this proceeding at Exhibit C, Tab 1, Schedules 1, 2, and 3.

CURRICULUM VITAE OF
LINDA AU

Experience: Enbridge Gas Distribution Inc.

Capital Budget Manager
2007

Capital Budget Supervisor
1995

Revenue and Gas Cost Analyst
1991

Canada Post Corporation

Operations Planning and Budget Officer
1990

Financial Analyst
1988

Queen Elizabeth Hospital

Senior Accountant
1986

Education: Certified General Accountant
CGA Ontario 1991

Bachelor of Business Management
Ryerson 1986

Appearances: (Ontario Energy Board)
EB-2009-0055
EB-2008-0219
EB-2006-0034
RP-2005-0001

CURRICULUM VITAE OF
ROBERT ALAN BOURKE, CMA

Experience: Enbridge Gas Distribution Inc.

Manager Regulatory Proceedings
2004

Manager Budget and Administration – Operations
2003

Manager Regulatory Accounting
1998

Senior Analyst Regulatory Accounting
1995

Supervisor Revenue and Gas Cost
1992

Centra Gas (Ontario) Inc.

Supervisor, Budget Administration
1992

Thornhill Glass & Mirror Inc.

Controller
1988

The Consumer Gas Company Limited

Manager System Customer Billing
1987

Management Trainee
1986

Supervisor Income and Cash Budget
1982

Asst. Supervisor Income and Cash Budget
1980

Education: Certified Management Accountant (CMA), 1981

Memberships: The Society of Management Accountants Ontario

Appearances: (Ontario Energy Board)
EB-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
MICHAEL BROPHY

Experience:	Enbridge Gas Distribution Inc.
	Manager, DSM & Portfolio Strategy 2004
	Manager, Sales 2001
	Senior Specialist, Environment Health & Safety 1999
	Environmental Coordinator, Environmental Affairs 1994
	Pipeline Inspector - GTA 1993
	Public Works Canada Environmental Engineering Assistant Architecture & Engineering Services 1993
	Assistant Project Officer 1992
Education:	Masters of Business Administration, University of Toronto 2004
	Masters of Engineering, Civil Engineering, University of Toronto 1997
	B.A.Sc., Civil Engineering, University of Waterloo 1994
Memberships:	Professional Engineers of Ontario Ontario Society for Environmental Management
Appearances:	(Ontario Energy Board) EB-2009-0154 EB-2009-0103 EB-2008-0384 EB-2008-0346 EB-2008-0271 EB-2007-0893 EB-2006-0034

EB-2006-0021
EB-2005-0001
EBLO 261/EBC 266/EBA 785
EBLO 260
EBLO 261
EBC 266
EBA 785
PL 97

CURRICULUM VITAE OF
IRENE CHAN

Experience: Enbridge Gas Distribution

Manager, Margin Budgets and Accounting
2007

Manager, Margin Planning and Analysis
2006

Manager, Volumetric Analysis and Budgets
2003

Supervisor, Volumetric Analysis
2001

Senior Analyst, Volumes Knowledge Centre
2000

Economic Analyst, Economic Studies
1998

Queen's University

Instructor, Economics Department
1997

Research/Teaching Assistant, Economics Department
1992-1997

International Monetary Fund

Summer Intern, Research Department
1996

Consultant, Research Department
1994

Bank of Canada

Research Assistant, Research Department
1991

Education: Certified Management Accountant,
The Society of Management Accountants of Canada, 2006

Ph.D. in Economics
Queen's University, 1998

Master of Arts in Economics
Queen's University, 1993

Bachelor of Arts (Honours) in Economics
University of Western Ontario, 1991

Memberships: Toronto Association for Business & Economics
The Society of Management Accountants of Canada

Appearances: (Ontario Energy Board)
EB-2009-0055
EB-2008-0219
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2002-0133

CURRICULUM VITAE OF
CLIFFORD F. CLARK

Experience: Enbridge Gas Distribution Inc.

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

Appearances: (Ontario Energy Board)
(Leave to Construct)
- Lakefield
- 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-2008-0106
EB-2009-0055
EB-2008-0219
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-3665-2008
R-3637-2007
R-3621-2006
R-2587-2005
R-3537-2004
R-3464-2001
R-3446-2000

CURRICULUM VITAE OF
KEVIN CULBERT

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Accounting
Current

Manager, Regulatory Accounting
2003

Senior Analyst, Regulatory Accounting
1998

Analyst, Regulatory Accounting
1991

Assistant Analyst, Regulatory Accounting
1989

Budgets – Capital Clerk, Budget Department
1987

Accounting Trainee, Financial Reporting
1984

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

Appearances: (Ontario Energy Board)
EB-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
JOEL DENOMY

Experience:	Enbridge Gas Distribution Inc.
	Manager, Economic and Market Analysis 2007-Present
	Supervisor, Economic and Market Analysis 2006-2007
	Senior Market Analyst, Volumetric and Market Analysis 2003-2006
	Market Analyst, Volumetric and Market Analysis 2002-2003
	AGF Management Limited
	Internal Auditor, Internal Audit 2001
Education:	Chartered Financial Analyst CFA Institute, 2006
	Master of Arts (Economics) University of Waterloo, 2002
	Bachelor of Arts (Honours Economics, Finance Specialization) University of Waterloo, 1999
Memberships:	Canadian Association of Business Economists (CABE) Toronto CFA Society
Appearances:	(Ontario Energy Board) EB-2008-0219 EB-2007-0615 EB-2006-0034 EB-2005-0001 RP-2003-0203
	(Régie de l'énergie) R-3587-2005 R-3665-2008
	(New York State Public Service Commission) 08-G-1392

CURRICULUM VITAE OF
JANE HABERBUSCH

Experience:	Enbridge Gas Distribution Inc.
	Director Human Resources 2001
	Sr. Organizational Effectiveness Consultant 2000
	Manager HR Planning & Development 1998
	Manager HR Planning 1996
	Human Resources Advisor 1993
	Manager Customer Systems 1991
Education:	Bachelor of Science (Honours) University of Toronto, 1978
	Certified Human Resources Professional University of Toronto, 2000
Memberships:	Human Resources Professional Association of Ontario
Appearances:	(Ontario Energy Board) EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2002-0133

CURRICULUM VITAE OF
PATRICK J. HOEY

Experience: Enbridge Gas Distribution Inc.

Director, Business Development
2008

Director, Regulatory Affairs
2004

Anbrer Consulting

Principal
2002

Union Gas Limited and Centra Gas Ontario Inc.

Strategic Accounts Manager
2001

Director, Corporate Development
2000

Director, Year 2000 Program
1998

Director, Environment & DSM
1995

Centra Gas Ontario Inc.

Director, Regulatory Affairs
1992

Manager, Rate Design
1989

Supervisor, Rate Design and Cost of Service Studies
1987

Canadian Radio-Television Telecommunication Commission - Ottawa

Tariff and Rate Analyst - Telecommunications
1984

Department of Energy, Mines and Resources - Ottawa

Economist - Natural Gas Branch
1983

Canadian Transport Commission - Ottawa

Economist - Air Transport Branch
1982

Education: Honours Bachelor of Arts, Economics/Geography
Carleton University, 1980

Masters of Business Administration
York University, 1982

Certified General Accountants Association of Ontario
Student - 5^{th} Year Level

Memberships: Canadian Gas Association - Chairperson CGA Regulatory Subcommittee

Appearances: (Ontario Energy Board)
EB-2007-0615
EB-2006-0034
EB-2005-0551
EB-2005-0001
EBRO 499
EBO 177-17
EBRO 493/494
EBRO 483/484
EBRO 477
EBRO 474-A
EBO 169-III
EBRO 474
EBRO 471
EBRO 467
EBRO 461
EBRO 458
EBRO 440-2
EBRO 411-III-A

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-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-3621-2006 R-3587-2006 R-3537-2004

CURRICULUM VITAE OF
SAGAR KANCHARLA

Experience:	Enbridge Gas Distribution Inc.
	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-2006-0034 EB-2006-0066 EB-2005-0539 EB-2005-0001 RP-2004-0015 RP-2003-0203

CURRICULUM VITAE OF
NARIN KISHINCHANDANI

Experience: Enbridge Gas Distribution Inc.

Director, Finance & Control
2006

Chief Accountant
2005

Manager, Financial Reporting and Analysis
2003

Supervisor, Internal Reporting
2002

Senior Financial Analyst
2001

V. Dewan & Co, Chartered Accountants, Thornhill, ON

Senior Associate
1997

Mettle Financial Services Pvt. Ltd., Mumbai, India

Consultant
1995

Credit & Commerce Finance Ltd., Nairobi, Kenya

Financial Controller
1993

Across Africa Safaris Ltd., Nairobi, Kenya

Financial Controller
1991

20th Century Finance Corporation, Mumbai, India

Assistant Manager, Leasing
1990

Education:	Certified General Accountant Certified General Accountants of Ontario, 2001
	Certified Public Accountant State of Colorado (Board of Accountancy), 2000
	Chartered Accountant (India) Institute of Chartered Accountants of India, 1991
	Master of Business Administration Syracuse University, NY, 1989
	Bachelor of Business Administration United States international University, CA, 1987
	Bachelor of Commerce University of Bombay, India, 1984
Memberships:	Certified General Accountants of Ontario State of Colorado (Board of Accountancy) - Certified Public Accountant Institute of Chartered Accountants of India
Appearances:	(Ontario Energy Board) EB-2008-0219 EB-2006-0034

CURRICULUM VITAE OF
THOMAS J. LADANYI

Experience: Enbridge Gas Distribution Inc.

Manager, Budgets and Financial Analysis
2007

Manager, Budgets and Planning
2005

Manager, Regulatory Proceedings
1999

Manager, Operations Information Technology
1998

Manager, Regulatory Services
1997

Manager, Regulatory Administration and Special Projects
1994

Manager, Regulatory Accounting
1991

Manager, Engineering Projects
1990

Trans Canada Pipe Lines Ltd.

Manager, Project Services
1989

Manager, Pipeline Design
1988

Assistant Manager, Pipeline and Station Facilities
1985

Supervising Engineer, Construction Planning and Pipeline Design
1983

Assistant Supervising Engineer, Quality Control
1981

Various Positions in Engineering and Operations
1974 to 1980

University of Toronto

Teaching Assistant
1972

Education: Executive Program
Queen's University, 1997

Certified Management Accountant,
Society of Management Accountants, 1987

Master of Applied Science
University of Toronto, 1974

Bachelor of Engineering
McGill University, 1972

Memberships: Association of Professional Engineers of Ontario
Society of Management Accountants of Ontario
American Society of Mechanical Engineers

Appearances: (Ontario Energy Board)
EB-2009-0055
EB-2008-0219
EB-2006-0034
EB-2005-0001
RP-2004-0203
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2002-0106
RP-2001-0032
RP-2000-0040
EBRM 106
EBRM 105
EBRO 490
EBRO 487
EBRO 485
EBRO 479
EBRO 473-A
EBLO 238

(National Energy Board)
RH-3-89
GH-1-89
GH-4-88
GH-3-88

(Public Service Commission of New York State)
70363 (Iroquois Pipeline)

CURRICULUM VITAE OF
LISA L. LAWLER

Experience: Enbridge Gas Distribution Inc.

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)
RP-2002-0133

CURRICULUM VITAE OF
RAYMOND LEI

Experience:	Enbridge Gas Distribution Inc.
	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-2008-0219 EB-2009-0055

CURRICULUM VITAE OF
STUART MURRAY

Experience:	Enbridge Gas Distribution Inc.
	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-2006-0034

CURRICULUM VITAE OF
DONALD R. SMALL

Experience: Enbridge Gas Distribution Inc.

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-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
MANNY SOUSA

Experience: Enbridge Gas Distribution Inc.

Manager Community & Government Relations
2008

Manager Community Relations
2004

Manager Community and Event Services
1999

Manager, Appliance Centres
1998

Black Photo Corporation

Regional Sales Manager
1990

Store Manager
1981

Education: University of St. Michael's College at University of Toronto
Certificate in Corporate Social Responsibility

Boston College
Certificate in Corporate Community Involvement

Seneca College
Business Diploma

Memberships: Agincourt Community Services Association
Board of Directors

Smart Commute North Toronto/Vaughan
Board of Directors

Scarborough Chamber of Commerce
Past Chair

CURRICULUM VITAE OF
PATRICIA A. SQUIRES

Experience: Enbridge Gas Distribution

Manager, Market Development
2008

Manager Mass Markets and New Construction Market Development
2006

Manager, Energy Technology
2004

Manager, DSM and Program Evaluation
2001

Manager, Planning and Evaluation
1998

Senior Evaluation and Market Planning Analyst
1997

Conservation Analyst
1994

Economic Researcher
1991

Research Assistant
1990

Education: Master in Environmental Studies
York University, 1996

Bachelor of Applied Arts (Applied Geography)
Ryerson Polytechnic University, 1990

Certificate in Economic Analysis
Ryerson Polytechnic University, 1990

Appearances: (Ontario Energy Board)
EB-2009-0154
EB-2008-0150
EB -2006-0021
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2000-0040
RP-1999-0001

(Régie du Gaz Naturel)
R-3355-96

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

The Canadian Institute

Conference Producer
1997

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-2009-0055
EB-2008-0219
EB-2008-0106

(Régie de l’énergie)
R-3665-2008
R-3692-2009

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-2005-0001
RP-2003-0203

CURRICULUM VITAE OF
KERRY LAKATOS-HAYWARD

Experience: Enbridge Gas Distribution

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
MICHAEL LISTER

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Policy & Strategy
2010

Manager, Investment Planning
2006

Manager, Volumetric & Market Analysis
2004

Supervisor, Volumetric & Market Analysis
2003

Sr. Market Analyst, Volumetric & Market Analysis
2002 - 2003

NRI Industries Inc.

Production Scheduler, Logistics
1999-2000

Fairlee Fruit Juices Ltd.

Raw Materials Coordinator
1998

Coats Canada Inc.

Production Planner, Materials & Logistics
1996-1997

Education: Chartered Financial Analyst
CFA Institute, 2005

Master of Business Administration
York University, 2002

Bachelor of Commerce
St. Mary's University, 1996

Memberships: CFA Institute
Toronto CFA Society

Appearances: (Ontario Energy Board)
EB-2009-0084
EB-2007-0615
EB-2005-0001
RP-2003-0203

(New York Public Service Commission)
05-G-1635

(New York Public Service Commission)
08-G-1392

CURRICULUM VITAE OF
ANDREW MANDYAM

Experience: Enbridge Gas Distribution Inc.

Manager, Demand Side Management and Portfolio
2010

Customer Information System Replacement Project Business Manager
2007

Manager, Customer Care and Customer Information System Program Operations
2006

Manager, Information Technology Solutions and Support
2005

Senior Project Manager, Information Technology Solutions and Support
2003

Oracle Corporation

Managing Consultant
1997

Compaq Canada

Program Manager
1995

Ontario Hydro

Associate Engineer
1990

Education: B.A.Sc. Mechanical Engineering
University of Toronto
1990

Memberships: Professional Engineers of Ontario
Project Management Institute

CURRICULUM VITAE OF
BORIS VISNJEVAC

Experience:	Enbridge Gas Distribution Inc.
	Manager Performance, Extended Alliance, Operations Services 2006
	Manager Market Development, Distributed Energy, Sustainable Growth 2005
	Program Manager, Energy Technology, Sustainable Growth 2004
Education:	Bachelor of Applied Science Department of Metallurgy and Material Science University of Toronto, 1999
Memberships:	Professional Engineers Ontario 2002

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 degree days appropriate?

3) Is the forecast of average use appropriate?

4) Is the forecast of customer additions appropriate?

5) Is the gas volume budget 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) What regulatory treatment will the Board apply to the 2010 costs of Green Energy Initiatives commenced under the authority of the Minister's Directive issued on September 8, 2009? In conjunction with this issue: (a) does the Board approve Enbridge offering the Green Energy Initiatives as new regulated energy services? and (b) is the amount of the 2010 Green Energy Initiatives Y-factor appropriate?

9) Is the amount proposed for the Y factor – Others appropriate?

10) Is the adjustment calculated for the Tax Rate and Rule Change variance account ("TRRCVA") appropriate?

Witness: R. Bourke

Is the amount proposed for the Pension Funding costs Z factor appropriate and is it appropriate to establish a Pension Funding costs variance account (“PFCVA”)?

11) Is the amount proposed for the Crossbores/Sewer Laterals Z factor appropriate and is it appropriate to establish a Crossbores/Sewer Laterals costs variance account (“CBSLCVA”)?

12) Is it appropriate to approve the following deferral (“DA”) and variance (“VA”) accounts:
   a) The previously established and agreed upon list of DA’s and VA’s from the EB-2007-0615 proceeding which were Approved for use during the IR period?
   b) The International Financial Reporting Standards Transition costs deferral account (“IFRSTCDA”)?
   c) The Open Bill Revenue variance account (“OBRVA”) and the Ex-Franchise Third Party Billing Services deferral account (“EFTPBSDA”)? and
   d) The Purchased Gas Variance Disposition Change Cost VA (“PGVDCCVA”) and the Mean Daily Volume Mechanism DA (“MDVMDA”)?

13) How should the new rates be implemented?

2010 RATE ADJUSTMENT SUMMARY

1. The Company is proposing to adjust its rates for the 2010 fiscal year within the parameters established in the Board Approved Incentive Regulation ("IR") formula (EB-2007-0615 dated 11-Mar-2008). The Settlement Agreement from that proceeding has been filed at Exhibit E, Tab 1, Schedule 1 for reference in this proceeding, if required.

2. The Company has proposed an approach which is designed to adjust rates to be implemented effective in January 2010 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 factor and Z factor recovery amounts included in the proposed 2010 rate adjustment have been filed primarily in the "B" series of exhibits. The 2010 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 factors filed in Tab 2 and Z factor evidence filed in Tab 3. The proposed rate schedules are found at Exhibit B, Tab 4, Schedule 2, with the balance of the schedules filed in Tabs 4 and 5 representing material that has been submitted in support of the development of the rate schedules.

4. The evidence filed in the "C" series of exhibits relates primarily to deferral and variance account evidence for the 2010 Test Year.

5. The 2008 historical year information was filed, reviewed and adjudicated in the EB-2009-0055 Earnings Sharing Mechanism ("ESM") proceeding. That material is available (1) on the Board's eFilingServices website under docket EB-2009-0055 or (2) in electronic format by request to the Regulatory department staff at Enbridge.

6. The information provided in the "E" series of exhibits has been filed for reference purposes as it represents evidence that has been brought forward from an earlier proceeding. Exhibit E, Tab 3, Schedule 1, which provides the ROE that results from the application of the Board Approved formula for the calculation of return on equity, will be filed when the underlying forecast information referred to as the 'October Consensus Forecast' is available (usually in late October).[1]

Updated Evidence

7. The Company has submitted updated evidence dated January 22, 2010 in compliance with Procedural Order #3 issued December 23, 2009. The updated evidence reflects the impact of Board decisions that have been issued since the Company's evidence was filed on October 1, 2009, including (1) the Board's denial, and the Company's subsequent withdrawal of, the proposed Green Energy Initiatives, (2) the withdrawal of the DSM – Solar Thermal Water Heater program, and (3) the Board's Decision in the EB-2009-0084 proceeding which reset the ROE determination to meet the Fair Return Standard and a refinement of the formula used to determine the annual adjustment to the ROE.

[1] This evidence has changed. Please refer to Exhibit E, Tab 3, Schedule 1 updated January 22, 2010.

8. The updated evidence also includes the impact of Provincial legislation changes to corporate income tax and capital tax rates, and the inclusion of an issue initiating a review of certain specific service quality requirements results for the 2007 and 2008 years.

9. The Company has also updated various other exhibits and schedules in order to reflect the impact of the updates noted above, including the cost allocation and rate design exhibits located at Exhibit B, under Tab 4.

10. There are a few new CV's filed to reflect witness changes as a result of recent organizational changes and an update to Exhibit B, Tab 7, Schedule 1 to provide actual deferral and variance account balances as at December 31, 2009 where a forecast balance had previously been provided. And finally, the Company has updated various exhibits in order to correct for minor informational and cosmetic errors or updates.

2010 REVENUE PER CUSTOMER CAP, DISTRIBUTION AND
TOTAL REVENUE DETERMINATION

Row		Col. 1 Original Filed 2010	Col. 2 Adjustments	Col. 3 Updated 2010
1.	2009 Total Approved Revenue	3,363.8		3,363.8
2.	Gas Costs to operations (at Oct. 1, 2008 ref. price)	2,389.7		2,389.7
3.	2009 Approved Distribution Revenue	974.1		974.1
4.	2009 Gas in storage related carrying costs (at Oct. 1, 2008 ref. price)	(50.4)		(50.4)
5.	DSM 2009 amount	(24.3)		(24.3)
6.	CIS / Cust. Care 2009 amount	(94.1)		(94.1)
7.	Power generation projects 2009 amount	(3.2)		(3.2)
8.	Distribution Revenue Sub-total	802.1		802.1
9.	Ratepayer 50% share of 2010 incremental tax amounts (Ex.C,T1,S4)	(3.8)	(2.80)	(6.6)
10.	Distribution Revenue base (subject to the escalation formula, $millions)	798.3	(2.80)	795.5
11.	Average Number of Customers (Beginning)	1,906,437		1,906,437
12.	Distribution Revenue per Customer 2010 (Beginning)	$ 418.74	(1.47)	$ 417.27
13.	GDP IPI FDD	2.73%		2.73%
14.	Inflation Coefficient (allowed % of GDP IPI FDD)	55.00%		55.00%
15.	Escalation Factor, 100 plus (GDP IPI FDD multiplied by the inflation coeff.)	101.50%		101.50%
16.	Distribution Revenue per Customer 2010 (Ending)	$ 425.02	(1.49)	$ 423.53
17.	Average Number of Customers (Ending)	1,931,528		1,931,528
18.	Distribution Revenue (resulting from the escalation formula, $millions)	820.94	(2.88)	818.06
	Y-Factors			
19.	2010 Gas in storage related carrying costs (at Oct. 1, 2009 ref. price)	36.70		36.70
20.	2010 DSM Y-factor amount	28.10	(1.40)	26.70
21.	CIS / Customer Care 2010 approved amount	95.70		95.70
22.	Power generation projects 2010 amount	3.70	(0.10)	3.60
23.	Green energy initiatives amount	0.30	(0.30)	-
24.	Total 2010 Y-Factors	164.50	(1.80)	162.70
	Z-Factors			
25.	2010 Pension funding requirement	18.90		18.90
26.	2010 Sewer Lateral / Cross Bore program requirement	3.60		3.60
27.	Total 2010 Z-Factors	22.50		22.50
28.	Total 2010 Distribution Revenues	1,007.94	(4.68)	1,003.26
29.	2010 Gas Costs to operations (at Oct. 1, 2009 ref. price)	1,453.50		1,453.50
30.	2010 Total Revenue	2,461.44	(4.68)	2,456.76

UPDATED EVIDENCE

2010 DISTRIBUTION REVENUE PER CUSTOMER CAP DISTRIBUTION AND TOTAL REVENUE DETERMINATION (2010)

Enbridge's revenue per customer cap calculation for 2010 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.

As shown on page 1, Column 3 of this schedule, the 2010 total revenue amount to be collected through rates is calculated through the completion of the following process. Formula amounts and percentage's being referred to below are all found in Column 3 of page 1.

Process

1. Row 1, $3,363.8 million, the starting point of the calculation, is the 2009 Total Board Approved revenue as per the EB-2008-0219 Final Rate Order. (Appendix A, p. 1, Column 1, Line 26)

2. Row 2, eliminates the gas cost of $2,389.7 million embedded within that total approved revenue to arrive at Row 3, the 2009 Board Approved distribution revenue of $974.1 million. Removal of this gas cost is necessary as it was based on prices underpinning the October 1, 2008 gas cost reference price of $387.103 /$10^3m^3$ and was relative to 2009 approved volumes[1]. The elimination is required in order to establish a base distribution revenue upon which the incentive escalation formula

[1] That reference price has been replaced within rates throughout each quarter in 2009. Prices underpinning the Oct. 1, 2009 reference price are embedded in the 2010 forecast of gas cost at the time of the 2010 application.

can be applied exclusive of gas costs. A 2010 forecast gas cost, outside of the incentive escalation formula, is included into the 2010 total revenue at Row 29, and is explained later in this evidence.

3. Row 3, shows the 2009 Board Approved distribution revenue of $974.1 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 EGD's approved revenue per customer cap model.

4. Row 4, eliminates $50.4 million, which is the embedded carrying cost on gas in storage and working cash related to gas costs in the 2009 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 2009 Board Approved distribution revenue which was based on 2009 approved volumes and prices underpinning the October 1, 2008 gas cost reference price of $387.103 /10^{3}m^3. This elimination is necessary, in order to establish a distribution revenue upon which the incentive escalation formula can be applied exclusive of carrying costs on 2009 gas in storage and gas cost working cash amounts related to 2009 approved volumes and gas cost prices. A carrying cost on gas in storage and gas cost working cash for 2010, outside of the incentive escalation formula, is included in the 2010 total revenue and explained at Row 19 later in this process. (Ref. Exhibit B-1-2, Appendix A)

5. Row 5, removes the 2009 Board Approved DSM operating costs of $24.3 million as established within the EB-2006-0021 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. The 2007 through 2009 approved DSM budgets were approved in EB-2006-0021 proceeding. The 2010 Board Approved DSM operating cost will be approved in the EB-2009-0154 (2010 Natural Gas DSM Plan) proceeding, and is included into the 2010 total revenue, outside of the incentive escalation formula, at Row 20.

6. Row 6, removes the 2009 Board Approved CIS/Customer Care costs of $94.1 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 2010 Approved CIS/Customer Care costs are included into the 2010 distribution revenue outside of the incentive escalation formula and are further outlined at Row 21.

7. Row 7, removes the 2009 Board Approved power generation related Y-factor revenue requirement amount of $3.2 million from the base subject to escalation. The inclusion of an updated 2010 revenue requirement amount of $3.7 million is shown at Row 22. Power generation project cost treatment was approved to be handled outside of the escalation portion of the incentive formula.

8. Row 8, shows a distribution revenue sub-total of $802.1 million, inclusive of all of the above noted adjustments. This is the exact amount of the Board Approved formula portion of 2009 rates as shown at Appendix A, page 1, Column 1, Row 18 of the EB-2008-0219 Rate Order.

9. Row 9, incorporates an incremental reduction to base rates of $6.6 million as shown in the updated Column 3, which is the 2010 ratepayer amount relating to updated

incremental tax rate and rule change expectations, (the original approved tax savings agreement would have reduced base rates by $3.7 million) agreed to be shared equally between ratepayers and the Company. At this time, the Company has proposed an update to the calculation of the amounts agreed upon and approved in relation to the anticipated tax rule and rate changes. The Company has filed evidence explaining the reason for the proposed update at Exhibit C, Tab 1, Schedule 4, Updated 2010-01-22.

10. Row 10, Column 3, shows the total base distribution revenue of $795.5 million, upon which the Approved incentive escalation formula can be applied.

11. Row 11, provides the 2009 Board Approved average number of customers of 1,906,437 (from EB-2008-0219, 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 Y and Z factors.

12. Row 12, Column 3, is the base distribution revenue per customer of $417.27, which is derived by dividing the Row 10 base distribution revenue of $795.5 million by the 2009 approved average customers of 1,906,437.

13. Row 13, 2.73%, 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-1-3.

14. Row 14, 55%, is the 2010 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 3, Row 15.

Witnesses: I. Chan
K. Culbert
A. Kacicnik
T. Ladanyi
D. Small

15. Row 15, 101.50% (or a multiplier of 1.0150) is the adjustment factor calculated as, 100% plus 1.50% (1.50% is calculated as the GDP IPI FDD inflation factor of 2.73% multiplied by 55%) which is required in the next step to arrive at an escalated average distribution revenue per customer amount.

16. Row 16, Column 3, $423.53, is the 2010 distribution revenue per customer which is calculated by multiplying the distribution revenue per customer at Row 12 of $417.27 by the adjustment factor of 101.50% or a multiplier of 1.0150.

17. Row 17, provides the 2010 forecast average number of customers of 1,931,528 which is found in evidence at Exhibit B-1-5.

18. Row 18, Column 3, $818.06 million, is the 2010 distribution revenue which is calculated by multiplying the 2010 distribution revenue per customer amount of $423.53 by the forecast 2010 average number of customers of 1,931,528. This distribution revenue is further adjusted in Rows 19 through 29 to arrive at a 2010 total revenue for which 2010 rates are developed.

19. Row 19, Column 3, increases the $818.06 distribution revenue by $36.7 million for carrying costs on 2010 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 2009 approved distribution revenue need to be removed from a base in order to apply an incentive escalation formula, the 2010 carrying cost on gas in storage and gas cost working cash related to 2010 forecast volumes and prices underpinning the October 1, 2009 gas cost reference price need to be included in the 2010 total revenue. This type of adjustment is required in order to develop rates which incorporate the upcoming 2010 volumetric forecasts and changes in approved gas

prices. (Ref. Exhibit B-1-2, Appendix A) and in order to ensure a proper baseline to which EGD's current approved rates which contain the October 1, 2009 approved gas cost reference price and associated carrying cost impacts can be compared.

20. Row 20, Column 3, increases the $818.06 million distribution revenue by $26.7 million, which is the Company's updated proposed 2010 DSM operating cost budget, found in evidence at Exhibit B, Tab 2, Schedule 2, Updated 2010-01-22. The addition of 2010 DSM costs, to 2010 total revenue, is required as 2009 DSM costs were previously removed as explained in the narrative for Row 5.

21. Row 21, Column 3, increases the $818.06 million distribution revenue by $95.7 million, the 2010 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.

22. Row 22, Column 3, $3.6 million, represents the 2010 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, Updated 2010-01-22, Exhibit B-2-1, Appendix A.

23. Row 23, Column 3, has been updated to zero to eliminate the 2010 revenue requirement associated with Y-factor capital expenditures for Green Energy Initiatives as a result of the removal of this request explained in updated evidence at Updated 2010-01-22, Exhibit B-2-4.

Witnesses: I. Chan
K. Culbert
A. Kacicnik
T. Ladanyi
D. Small

24. Row 24, Column 3, $162.70 million, is the sum of Rows 19 through 23, total 2010 Y-factors.

25. Row 25, $18.9 million, represents the Company's forecast 2010 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 (Ref. Exhibit B-3-1). Evidence supporting the recovery and treatment of this item and amount is shown in evidence at Exhibit B, Tab 3, Schedule 1, and Exhibit C, Tab 1, Schedule 2.

26. Row 26, Column 3, $3.6 million, represents the Company's forecast 2010 crossbores / sewer laterals initiative 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 (Ref. Exhibit B-3-2). Evidence supporting the recovery and treatment of this item and amount is shown in evidence at Exhibit B, Tab 3, Schedule 2, and Exhibit C, Tab 1, Schedule 3.

27. Row 27, $22.5 million, is the sum of Rows 25 & 26, total 2010 Z-factors.

28. Row 28, Column 3, $1,003.26 million, is Enbridge's total 2010 distribution revenue before gas costs which 2010 rates will be designed to recover.

29. Row 29, $1,453.5 million, is the 2010 forecast gas cost required to be added to the 2010 distribution revenue to establish 2010 total required revenue. The $1,453.5 million replaces the previously removed 2009 gas cost value embedded within the starting 2009 Total Board Approved revenue as explained in the narrative for Row 2. Evidence is found at Exhibits B, Tab 6, Schedules 1 and 2.

Witnesses: I. Chan
K. Culbert
A. Kacicnik
T. Ladanyi
D. Small

30. Row 30, Column 3, $2,456.76 million, is the 2010 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 2010 rates will be designed to recover this entire amount based on the forecast of 2010 volumes associated with the formula.

Witnesses: I. Chan
K. Culbert
A. Kacicnik
T. Ladanyi
D. Small

2010 FORECAST GAS IN STORAGE
IN RATE BASE AND ITS ASSOCIATED
GROSS CARRYING COST

		Col.1	Col.2	Col.3
Line No.		Exhibit Reference		
				($000)
		EB-2009-0172	(10^3m^3)	
1.	Average gas in storage volume & value	Exhibit B.T6.S2.pg.4, line 14	1 400 189.5	373,218.8
2.	Gas cost working cash allowance			
2.1	a) Purchase cost of gas		$1,566,037.3	
2.2	b) Net lag-days calculated	EB-2009-0309,Q4-3.T2.S2.line 3.2	4.5	
2.3	c) Dollar days		7,047,167.9	
2.4	d) Number of operating days		365	19,307.3
3.	Rate Base value			392,526.1
4.	Gross return component	(See page 3 of this schedule)		9.36%
5.	Carrying cost requirement			36,740.4

**2009 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-2008-0219	(10^3m^3)	
1.	Average gas in storage volume & value	Exhibit B.T5.S2.pg.4, line 14	1 160 383.9	511,235.1
2.	Gas cost working cash allowance			
2.1	a) Purchase cost of gas		$2,380,207.6	
2.2	b) Net lag-days calculated	EB-2008-0263,Q4-3.T2.S2.line 3.2	4.2	
2.3	c) Dollar days		9,996,871.9	
2.4	d) Number of operating days		365	27,388.7
3.	Rate Base value			538,623.8
4.	Gross return component	(See page 3 of this schedule)		9.36%
5.	Carrying cost requirement			50,415.2

CALCULATION OF THE GROSS RATE
OF RETURN ON RATE BASE

		Col.1	Col.2	Col.3	Col.4	Col.5
Line No.		Capital Structure Component	Indicated Cost Rate	Net Return Component	Reciprocal of the Tax rate	Gross Return Component
		(Note 1)	(Note 1)	(Note 1)	(Note 2)	
		%	%	%		%
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 2010 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]:

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

where, for example,

$$AG_{TestYear-1}^{Q2} = 100\left(\frac{Index_{TestYear-1}^{Q2}}{Index_{TestYear-2}^{Q2}} - 1\right)$$

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: J. Denomy

4. Table 1 outlines the calculation of the inflation factor for 2010. 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 2010 is 2.73%.

Table 1 - Inflation Factor
Calculation of Inflation Factor

Col. 1	*Col. 2*	*Col. 3*
Quarter	Index Value	Annualized Growth Rate
2006 Q4	108.50	
2007 Q1	109.80	
2007 Q2	110.60	
2007 Q3	110.20	
2007 Q4	110.60	
2008 Q1	111.30	
2008 Q2	112.40	
2008 Q3	113.60	3.09%
2008 Q4	114.20	3.25%
2009 Q1	114.40	2.79%
2009 Q2	114.40	1.78%
Average (Rounded to 2 decimal places)		2.73%

Witness: J. Denomy

CUSTOMER ADDITIONS

1. The purpose of this evidence is to provide the Company's forecast of customer additions for the Company's 2010 Test Year. The Company is forecasting 32,379 customer additions for 2010. This represents a decline of 8,862 customer additions relative to the 2009 Board approved forecast of 41,241 customer additions.

2. The customer additions forecast for 2010 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 deteriorated since the latter half of 2007, throughout 2008 and into 2009. Real output in the Ontario economy declined for three consecutive quarters beginning in the third quarter of 2008. In the first quarter of 2009, Ontario real gross domestic product declined, quarter over quarter, by 2.0% or 7.7% annualized. This reduction in economic output can be attributed to a variety of factors including the financial market meltdown and the subsequent recession in the U.S., Canada and abroad which has resulted in reduced consumer and business spending. Manufacturing, particularly the automotive sector, and exports in general, have continued to register declining growth rates albeit at a much faster pace relative to the period prior to roughly mid 2007. As a result of the recession, the number of individuals employed has dropped dramatically resulting in higher unemployment rates and lower disposable incomes. Projections for real

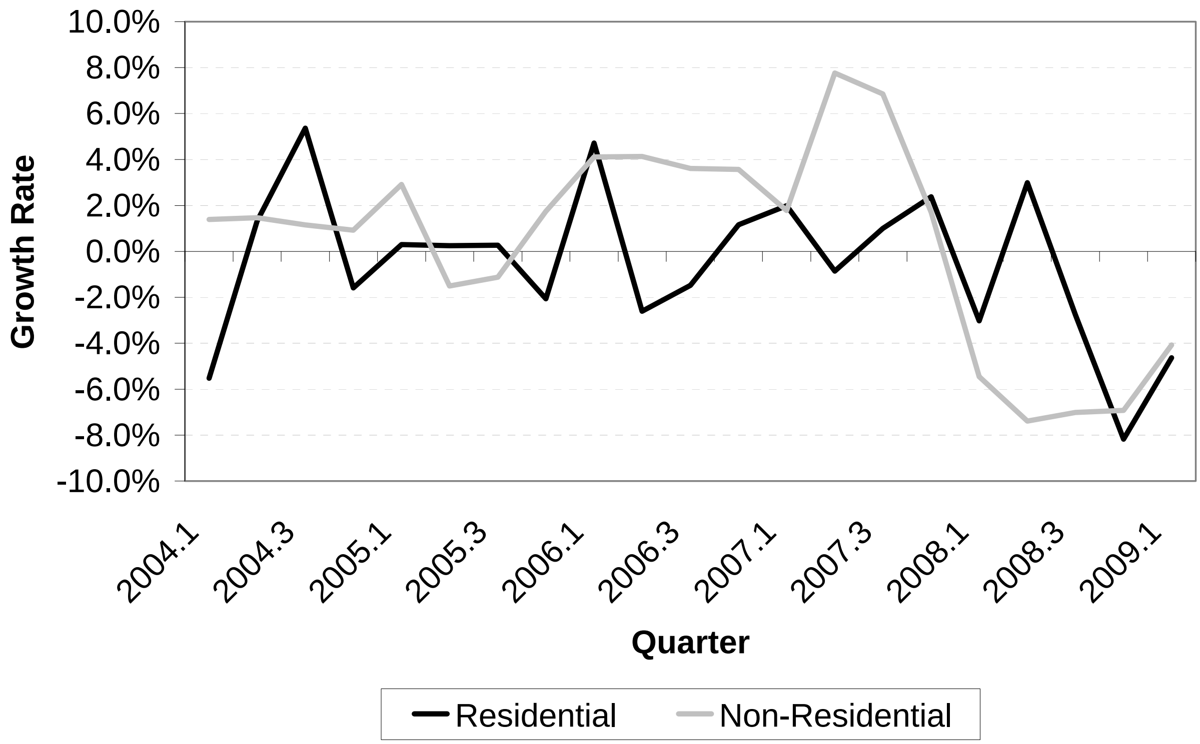
GDP growth over the next two years for Ontario are on average lower than the growth rates seen for the past five years. Table 1 contains a summary of the Company's Economic Outlook Spring 2009. Detailed tables outlining the Economic Outlook can be found at Exhibit B, Tab 1, Schedule 7, pages 21 to 24.

Table 1
Economic Outlook Summary

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Variable	2004	2005	2006	2007	2008	2009 Forecast	2010 Forecast
ONTARIO REAL GDP (% CHANGE)	2.6	2.8	2.6	2.3	-0.4	-1.8	2.1
MORTGAGE RATE 5 YEAR TERM (%)	6.23	5.99	6.66	7.07	7.06	5.23	5.37
ONTARIO HOUSING STARTS (000's)	85.1	78.8	73.4	68.1	75.1	55.1	56.8
CENTRAL REGION HOUSING STARTS (000's)	44.7	43.0	38.8	35.7	42.4	31.2	30.3
EASTERN REGION HOUSING STARTS (000's)	7.5	5.2	6.1	6.8	7.2	5.3	5.3
NIAGARA REGION HOUSING STARTS (000's)	2.0	1.5	1.4	1.3	1.3	0.9	1.0
FRANCHISE AREA HOUSING STARTS (000's)	54.2	49.7	46.4	43.8	50.8	37.5	36.6

4. Commensurate with the slowing of overall economic growth, Ontario real gross fixed capital formation in both residential and non-residential construction has also slowed. With these trends expected to continue throughout the remainder of 2009 and into 2010 both housing starts and the construction of new commercial and industrial structures is expected to slow. While 2010 is expected to be a year of recovery, investment in new housing and commercial/industrial buildings is expected to remain soft as projects are put off until an economic recovery is certain and the labour market improves. Figure 1 shows that the growth rate in real business fixed investment for both residential and non-residential structures has trended downwards over the past few quarters.

Figure 1: Ontario Real Gross Fixed Capital Formation



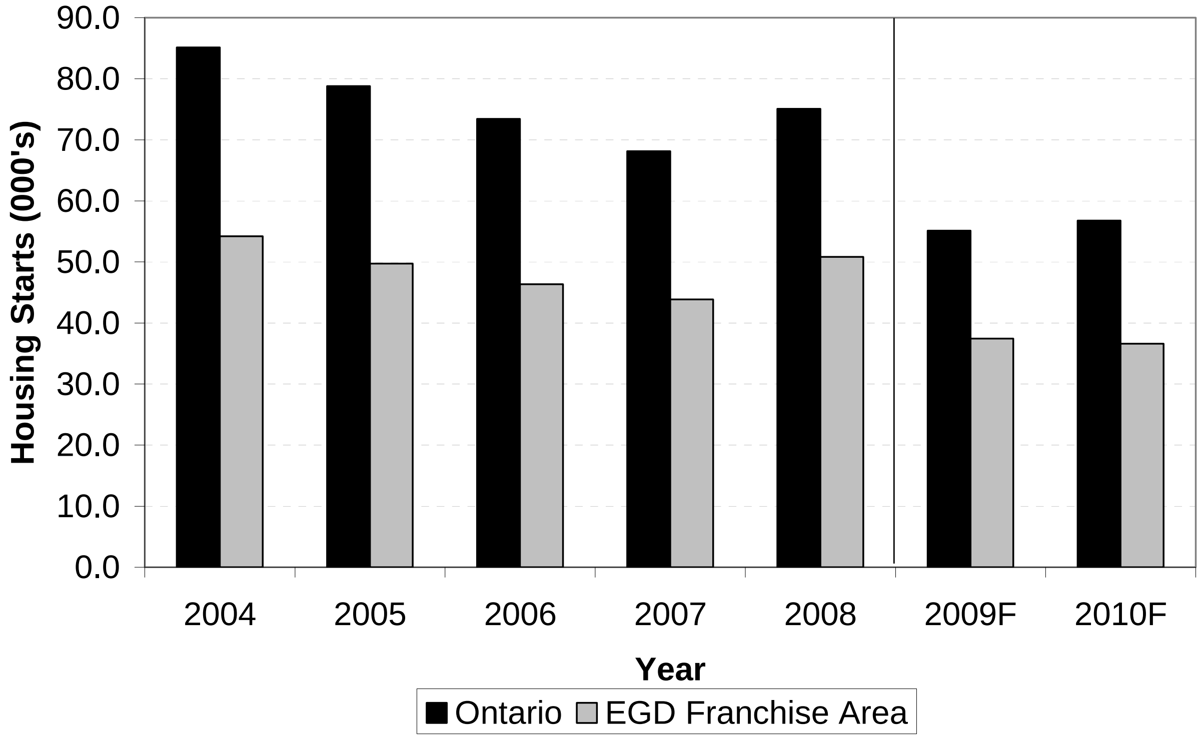
5. The most recent peak in Ontario housing starts occurred in 2003. At that point in time the target for the overnight rate set by the Bank of Canada was near historical lows, averaging 2.94% for the year. Recently the Bank of Canada has aggressively reduced interest rates in an attempt to free up credit 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 announced its intention to keep the overnight rate at this level until mid 2010. As a result mortgage rates have dropped to historic lows as well. Lower interest rates translate into lower financing costs for houses and commercial

structures. Consequently lower 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. Over the past five years housing starts in Ontario and the Company's franchise area have trended down since reaching a peak in 2003. The Company expects this trend to continue over the next two years. Throughout this time period approximately 65% of Ontario housing starts, on average, have resided in the Company's franchise area. Table 1 shows the Company's forecast of housing starts for 2009 and 2010. Despite lower interest rates the Company expects housing starts to decline in 2009, largely as a result of the recession and relatively tighter credit conditions. Expectations are for housing starts to remain relatively flat through to 2010. Figure 2 shows the general downward trend in housing starts for Ontario and the Company's franchise area since 2004. The increase in 2008 is attributable to a surge in apartment housing starts in Toronto.

Figure 2: Housing Start Trends



7. Furthermore, the new construction market is at risk from the resale market. The ratio of new home listings in Ontario to housing starts in Ontario has increased from 3.4 in 2003 to 5.1 in 2007 and 4.9 in 2008. 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.

Residential Customer Additions

8. Over the past 5 years, on average, residential customer additions have comprised approximately 93% of the Company's total customer additions. Since the vast majority of total customer additions are comprised of residential customer additions, trends in total customer additions will follow trends in the housing market.

Commensurate with the observed decline in housing starts in the Company's franchise area, residential customer additions have followed a similar trend. This trend is expected to continue in 2010. The Company is forecasting 29,790 residential customer additions for 2010. This forecast is comprised of 22,616 new construction customer additions and 7,174 replacement customer additions.

Apartment Customer Additions

9. Over the first quarter of 2008 it became apparent that there was a boom in apartment starts in Toronto. With the economic downturn this trend is expected to slow for the coming year. The Company is forecasting 26 apartment customer additions in 2010. Of this number, 19 are new construction customer additions and seven are replacement customer additions.

Commercial Customer Additions

10. The slowing economy is expected to put downward pressure on business investment in commercial non-residential structures. The Company is currently forecasting 2,553 commercial customer additions for 2010. This forecast is comprised of 1,665 new construction customer additions and 888 replacement customer additions.

Industrial Customer Additions

11. Much like the commercial sector, the recession will slow business investment in non-residential structures for the industrial sector. In addition, the manufacturing sector in Ontario is under pressure from a high Canadian dollar and foreign competition. The Company is forecasting 10 industrial customer additions for 2010, seven of which are new construction customer additions and three of which are replacement customer additions.

12. Table 2 provides the Company's forecast of customer additions for 2010. In summary, the economy and the expectation of a continued downward trend in housing starts are expected to cause customer additions to decline to a level of 32,379 in 2010. This represents a decline of 8,862 customer additions relative to the Company's 2009 Board approved customer additions forecast.

Table 2
Customer Additions

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Sector	2008 Actual	2009 Board Approved Budget	2010 Forecast
Residential			
New Construction	30,300	31,739	22,616
Replacement	7,742	6,548	7,174
Total	38,042	38,287	29,790
Apartment			
New Construction	22	41	19
Replacement	6	7	7
Total	28	48	26
Commercial			
New Construction	2,019	1,955	1,665
Replacement	957	941	888
Total	2,976	2,896	2,553
Industrial			
New Construction	5	8	7
Replacement	1	2	3
Total	6	10	10
Total Customer Additions	41,052	41,241	32,379

Witnesses: J. Denomy
S. Murray

GAS VOLUME BUDGET

1. The purpose of this evidence is to present the 2010 Test Year forecast of volumes and related information. This evidence is on a calendar-year billing-period basis (i.e., on a December fiscal year end basis) excluding the Historical Actual vs. Board Approved section. The 2010 forecast of gas volumes incorporates calendar 2008 actual billing consumption.

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)

	2008 Board Approved Budget	2008 Actual	2009 Board Approved Budget	2009 Bridge Year Estimate	2010 Budget
General Service Volumes	8 288.0	8 806.0	9 083.2	8 938.6	9 083.5
Contract Volumes	3 555.2	3 101.5	2 316.6	2 118.4	2 008.6
Total Volumes, Gas Sales and Transportation	11 643.2	11 907.5	11 399.8	11 057.0	11 092.1
Customers, Gas Sales and Transportation (Average)	1 864 047	1 865 020	1 906 437	1 900 696	1 931 528

Witnesses: I. Chan
T. Ladanyi

3. As a consequence of the implementation of the 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, but do have monthly contract demand volumes. Since these contract demand volumes also generate fixed contract demand revenues, Table 2 presents a summary of these contract demand volumes.

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

	2007 Board Approved Budget	2007 Actual	2008 Board Approved Budget	2008 Actual	2009 Budget	2009 Bridge Year Estimate	2010 Budget
Total Contract Demand Volumes	14.6	12.5	38.1	40.0	74.2	73.4	82.6

4. An unexpected migration of one large distributed energy customer from Rate 115 (bundled rate class) to Rate 125 (unbundled rate class) in July 2008 contributed to favourable contract demand volumes variance between 2008 Actual and 2008 Budget. However, this also caused a significant reduction in the bundled contract rate class distribution volumes of 202.0 10^6m^3 (2008 budget) annually going forward.

5. A one-month service delay of one power generation customer caused a slight reduction in contract demand volumes between 2009 Bridge Year Estimate and 2009 Budget. The increase in contract demand volumes between 2010 Budget and

2009 Bridge Year Estimate is primarily attributable to the full year service of this power generation customer. A further explanation of the contract demand revenue items is provided at Exhibit B, Tab 4, Schedule 4.

Comparison of 2010 Budget and 2009 Estimate - Summary

6. The 2010 Budget volumes reflect the meter reading heating degree days forecast for the Central Region of 3,546, an increase of 32 degree days compared to the 2009 Board Approved or 2009 Bridge Year Estimate of 3,514. Meter reading heating degree days are calculated 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. The 2010 degree day forecast is calculated using the 20-Year Trend methodology that was approved by the Board in its EB-2006-0034 Decision with Reasons.

7. The 2010 Budget volumes of 11 092.1 10^6m^3 are forecast to be 35.1 10^6m^3 or 0.3% above the 2009 Bridge Year Estimate of 11 057.0 10^6m^3. This increase in volumes is attributable to the higher degree days forecast mentioned above and other factors that will be discussed below. On a weather-normalized basis, the 2009 Budget volumes are forecast to be 17.3 10^6m^3 or 0.2% below the 2009 Bridge Year Estimate. The decrease on a normalized basis is made up of a decrease in the contract market of 108.4 10^6m^3, partially offset by an increase in general service volumes of 91.1 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 1 to 6.

8. The increase in the general service volumes of 91.1 10^6m^3 on a weather-normalized basis is primarily due to customer growth of 87.4 10^6m^3, rate switching from contract rate to a general service rate class (or transfer gains) of 78.3 10^6m^3, and the

Company's incremental added load initiatives of 0.7 10^6m^3. These customer growth and added load volumes help to mitigate the lower average use per customer of 75.3 10^6m^3 resulting from the impact of the 2010 Demand Side Management ("DSM") plan, conservation initiatives originated by customers themselves or promoted by government programs, improved building envelopes, and an anticipated increase in natural gas prices between the 2010 Budget and the 2009 Bridge Year Estimate. Further explanations are provided in the general service volumes section on the next several pages.

9. The decrease of 108.4 10^6m^3 in the contract market on a weather-normalized basis is mainly caused by rate switching from a contract rate to general service rate class (or transfer losses) of 78.3 10^6m^3 along with reduction in usage. The shift between contract and general service rate classes seen in the 2010 Budget is a continuation of recent trends starting in the fall of 2006 and has been reflected in both 2009 and 2010 volumes. After removing the unfavourable rate switching volumetric impact, the 2010 contract market volume budget is expected to be 30.1 10^6m^3 lower than the 2009 Estimate. This underage is due to production decreases of 23.1 10^6m^3 primarily driven by one large customer and a loss in load of 7.0 10^6m^3 relating to plant closures or relocations. Further explanations are provided in the contract market volumes section on the next several pages.

10. The decrease in 2010 Budget and 2009 Estimate volumes is primarily attributable to the contract market customers who have been hard hit by the global economic downturn by reducing consumer demand in Canada and worldwide since last October's financial crisis. Consistent with previous year filings the Company has experienced ongoing contract market customer losses and reductions in usage that is a reflection of recent years' experience of unfavourable economic or business

conditions, such as strong Canadian dollar and global competitive cost pressures experienced in energy intensive manufacturing industries, such as pulp & paper, transportation equipment, primary metal, non-metallic mineral and chemical.

11. This year will mark the fourth annual decline in Ontario real manufacturing output as shown in Table 10 at Exhibit B, Tab 1, Schedule 7, page 22. The Ontario growth in real Gross Domestic Product ("GDP") has generally been below the national growth rate recent years since 2003.[1] Automobile and auto parts production declined more than 20%, while production of wood products dropped sharply. Weakened export demand contributed to a decline in 16 of 21 major manufacturing industry groups in Ontario. Recent slowing growth in the United States due to its subprime mortgage issues early in 2008 along with an unexpected major financial crisis in Fall 2008 have further exacerbated this declining manufacturing trend in Ontario.

12. As indicated in Statistics Canada's Labour Force Survey, while Ontario accounts for 39% of Canada working-age population, it has experienced 64% of overall employment losses since the start of the labour market downturn. Between October 2008 and May 2009, Ontario has experienced total losses in employment of 234,000. Manufacturing employment is the major driver behind these employment losses. In May 2009, there were 778,000 factory workers in Ontario, the lowest level since comparable data became available to Statistics Canada in 1976. Manufacturing employment in Ontario reached a peak in November 2002 with 1,115,000 workers.[2]

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[1] "Provincial and territorial economic accounts, 2008." *The Daily*. Statistics Canada, Apr. 2009. <http://www.statcan.gc.ca/daily-quotidien/090427/dq090427a-eng.htm>.
[2] "Labour Force Survey." The Daily. Statistics Canada, May 2009. <http://www.statcan.gc.ca/daily-quotidien/090605/dq090605a-eng.htm>.

13. Overall, these unfavourable business conditions and economic environment negatively impact consumer spending (purchasing power) which led to a reduction in customer additions as stated at Exhibit B, Tab 1, Schedule 4, and General Service average use all else being equal.

14. Although it is expected the economy will recover in 2010 as shown in Table 10 at Exhibit B, Tab 1, Schedule 7, the percentage change (i.e. growth) will not be enough to restore it to the 2007 level and offset the losses in Ontario Real GDP and Ontario Real Manufacturing Output occurred during 2008-2009. Also, the employment level will trend below historical levels as the unemployment rate for 2010 is still higher than 2004 actual level. As quoted by the Ontario Minister of Finance, the global economy has entered into a crisis that was not experienced for some 80 years.[3] Overall, the 2010 budget represents the forecast that integrates all the actual experience and the best known information about contract customers at the time of the development of the budget.

General Service Demand Forecast Methodology

15. The general service volumes were derived using the Company developed regression models. The regression model methodology was introduced in RP-2000-0040 and has been accepted by the Board since then.

16. Consistent with previous rate cases, the Company is committed to continue reporting 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 as agreed in RP-2000-0040 Settlement Agreement at Issue 1.1. Average

[3] "Public Accounts of Ontario 2008-2009 Annual Report and Consolidated Financial Statements." Ministry of Finance. Sep.25, 2009. <http://www.fin.gov.on.ca/english/budget/paccts/2009/09_ar.html>

in-sample forecast error for both Rate 1 and Rate 6 regression models is still less than one percent on average during 2001 to 2008 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.

17. Annual econometric models were 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 2009* filed at Exhibit B, Tab 1, Schedule 7. This was the latest information available at the time the forecast was developed. As average use regression models are on an annualized basis, the regression models forecast includes 2008 actual billing consumption information up to and including December 2008.

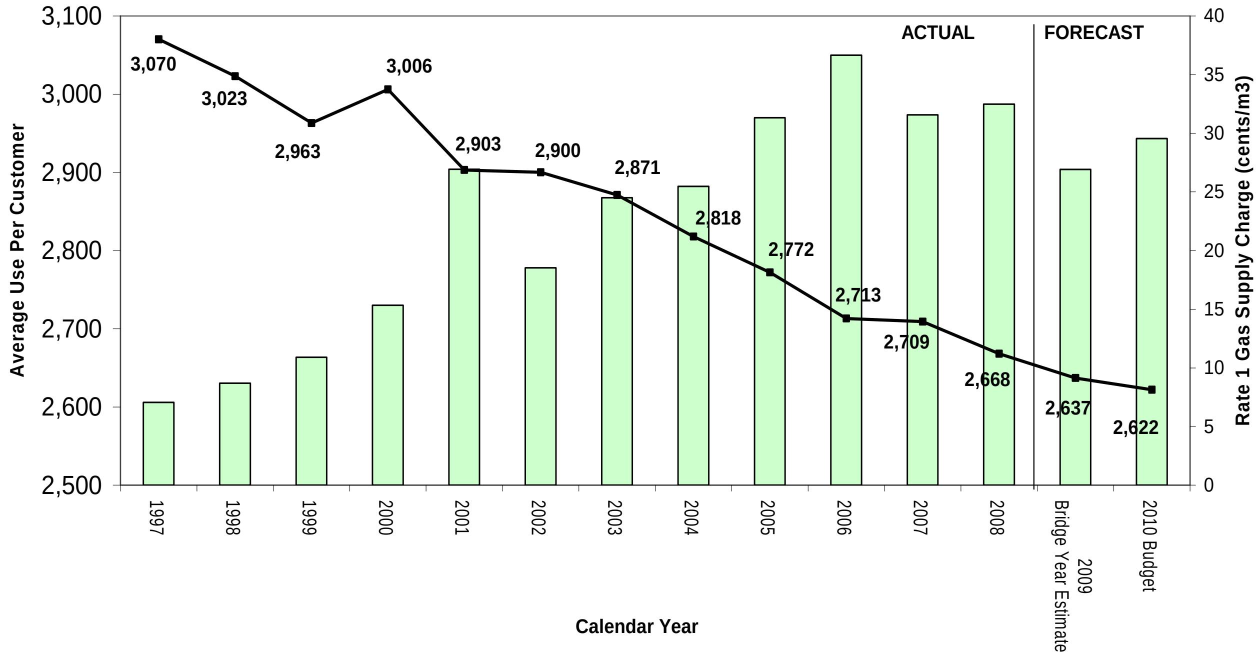
18. The major driver variables in the Rate 1 and Rate 6 models are heating degree days, vintage (Rate 1 only), employment, Ontario real gross domestic product, Ontario real gross domestic product by manufacturing industry, vacancy rates (Rate 6 only), real energy prices, and time trend. The vintage variable was constructed to reflect the impact of new homes associated with more energy efficient gas equipment over time and building codes. Gas equipment includes gas furnaces, water heaters, and stoves. The employment and other economic variables reflect the fact that additional gas appliances, such as pool heaters, would be more affordable under favourable economic conditions, in conjunction with the Company’s added load initiatives such as fuel switching, would increase average use and vice versa. The time trend including the dynamic variable in the regression model captures the historical actual average trend of the sectoral average use, such as the impact of historical rate switching on average uses, 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 variable assumptions can be found at Exhibit B, Tab 1, Schedule 7.

General Service Volumes: 2010 Budget

19. From 1998 to 2008, normalized residential average use has declined by an average of 37.0 m^3 or 1.3% per year for each residential customer. However, during the volatile and high natural gas price period between 2001 and 2006, normalized residential average use has decreased by an average of 49.0 m^3 or 1.7% per year for each residential customer. Figure 1 below shows the residential average use from 1997 to the 2010 Test Year, on a weather normalized basis, as filed at Appendix A, page 21.

Figure 1
Residential Normalized Average Use (m^3)



20. Table 3 quantifies the volumetric impact of the average use driver variables on the residential sector's average use forecast and customer growth, respectively. On a weather-normalized basis, the increase in the residential volumes of 54.2 10^6m^3 is a result of positive customer growth, partially offset by the ongoing average use decline as shown in Figure 1 and discussed in the following paragraphs.

21. Compared with the 2009 Bridge Year Estimate, residential average uses will continue to decline in 2010. This decline is due to the following:

- the Company's DSM initiatives;
- other conservation initiatives originated by customers themselves or promoted by government programs (e.g., Green Energy Act, ecoENERGY Retrofit, Solar

H2Ottawa, Ontario Home Energy Audit and Retrofit, and Ontario Solar Thermal Heating Incentive);

- space heating and water efficiency gains due to ongoing furnace stock turnover and new construction additions with more energy efficient furnaces;
- higher gas prices predicted in 2010 than in 2009;
- 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;

partially offset by:

- the Company's added load initiatives; and
- the penetration of new gas appliances as a result of positive employment growth in 2010.

Table 3

Factors Influencing the Changes in Residential Gas Consumption Between 2010 Test Year Budget and 2009 Bridge Year Estimate (10^6m^3)

Factors	Total Volume (10^6m^3)	
Customer Growth	79.6	
DSM Initiatives	(13.7)	
New Homes - historical trend (a)	(9.2)	
Gas Prices	(3.0)	
Other Conservation (b)	0.0	*
Gas Appliances (c)	0.0	*
Growth Initiatives or Added Load (d)	0.5	
Total	54.2	

(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, and requiring 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.

(d) Added Load is based on the Company's added load initiatives, such as fuel switching, etc.

* Less than 50,000 m^3

22. On June 28, 2006, the Government of Ontario introduced a new 2006 Building Code to increase energy-efficiency requirements for both residential and non-residential buildings relative to the existing 1997 Building Code to be effective December 31, 2006. This new building code set a new requirement for more energy efficient windows, higher insulation levels or improved building envelopes,

and a higher efficiency rating of 90% for gas and propane-fired instead of the current minimum 78% efficiency requirement. All else being equal, the Government of Ontario estimated that a structure built under this new Building Code will be 21.5% more efficient than the one built under the 1997 Building Code. Further building code changes related to energy efficiency will be phased in during 2009 for requiring near-full-height basement insulation and in 2012 the requirement for meeting standards in accordance with the national guideline, EnerGuide 80.[4]

23. Based upon historical actual data to 2008, the regression model will not be able to predict an incremental average use reduction reflecting the near-full-height basement insulation in new houses between the new building code effective December 31, 2008 and the old code. Consequently, the incremental impact of 1.8 10^6m^3 shown in Table 2 is layered onto the regression model's average use forecast for 2009 Estimate only. It is calculated by applying the Government of Ontario's estimated savings of 6.5% between 2008 and 2009 to the residential new construction customers that have space heating furnaces.

24. As most of the new customers will not move to their new houses and start consuming gas effective January 1 2009, the currently reported 1.8 10^6m^3 impact reflects the first year's partially effective impact. Beyond 2009, the fully effective impact of this new building code will be much larger than this first year's impact, all else being equal. There are no incremental savings or fully effective impact layered onto the 2010 Budget average use forecast due to insufficient information available from the Government of Ontario. In addition to these changes in energy-efficiency requirements for buildings, this new 2006 Building Code also includes new

[4] Please refer to the Ministry of Municipal Affairs and Housing web site for further technical information, http://www.mah.gov.on.ca/Page681.aspx.

provisions that will promote the use of green technologies such as active solar hot water systems, which can displace natural gas water heater usage in the future. As there is insufficient information available from the Government of Ontario in order to apply the estimated energy savings of these green technologies promoted by recent Ontario's Green Energy Act and renewable technologies such as, stationary fuel cells, wind, water, biomass, biogas, solar and geothermal energy generation facilities, the risk of incurring larger residential volume loss than budgeted is weighted heavily to the downside.

25. After considering an increase in the penetration rate of high efficiency furnaces in the Canadian market in recent years due to increasing gas prices and price volatility, utility and government incentive and awareness programs, and better availability and acceptability of high efficiency products, Natural Resources Canada (NRCan) has amended the Regulations to increase minimum energy performance standards for residential gas furnaces in Canada. Effective December 31, 2009, the minimum performance level, Annual Fuel Utilization Efficiency ("AFUE"), for residential gas-fired furnaces will be 90% (high-efficiency) instead of the previously 78% (medium-efficiency).[5] The corresponding further reduction in average use has not been incorporated into the current volumetric forecast due to lack of data availability.

26. Further to the downside risk mentioned above, the current volumetric forecast also has not incorporated the potential adverse impact of further self-imposed energy conservation activities undertaken by customers with the implementation of the

[5] "Publication of Regulations Amending Canada's Energy Efficiency Regulations." Office of Energy Efficiency. Natural Resources Canada, December 2008.
<http://oee.nrcan.gc.ca/regulations/amendment10/publication.cfm?attr=0>

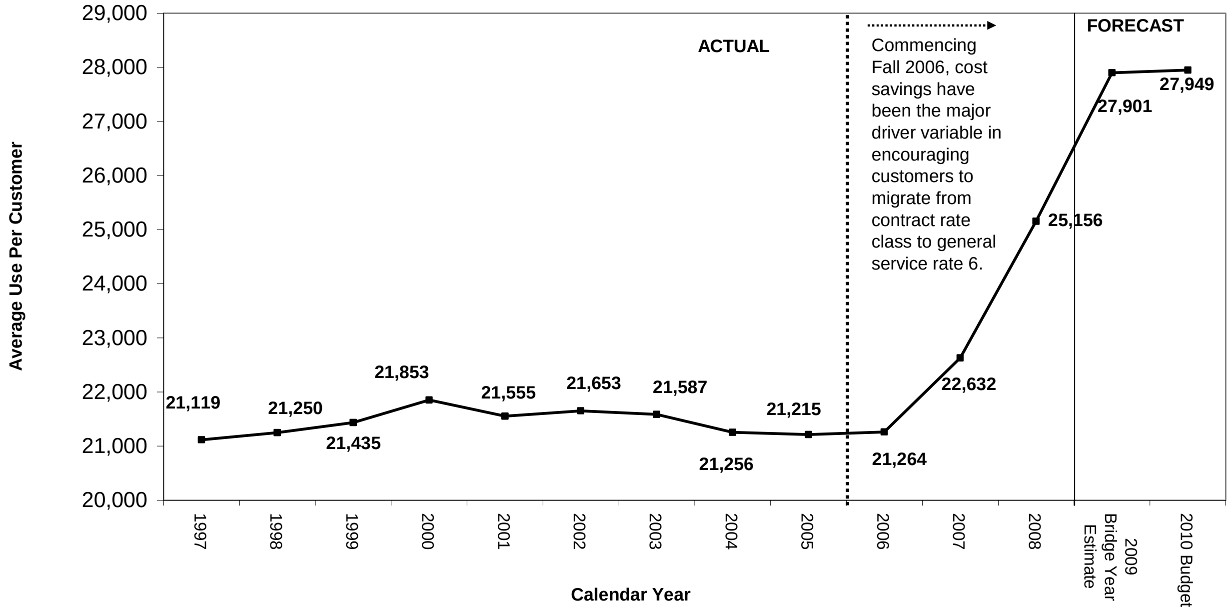
Harmonized Sales Tax (HST) in 2010 as suggested by Ontario Finance Minister.[6] Current natural gas customers are exempt from the provincial sales tax (8%). However, with the implementation of the blended tax rate effective July 2010, home energy costs will be increased by 8% all else being equal. As a result, customers may perceive this as a further increase in gas charges. This may further encourage customers to further reduce natural gas usage by taking advantage of energy retrofit or other renewable energy programs promoted by both Federal and Provincial governments.

27. Rate 6 is comprised of the apartment, commercial, and industrial sectors. From 1998 to 2008, normalized Rate 6 average use has increased by an average of 367 m^3 or 1.7% per year. The increase in 2007 and 2008 actual usage is largely attributable to the rate switching from contract customers to general service customers starting in the fall of 2006. The anticipated continuation of this trend is the primary reason for the increase in 2010 of Rate 6 average use budget numbers. Further explanation about this rate switching trend will be presented later.

28. Figure 2 shows the Rate 6 average use from 1997 to the 2010 Test Year on a test year weather normalized basis, as filed at Appendix A, page 21. Excluding the rate switching, impacted by new factors that are much higher than the historical trend, during the high and volatile natural gas price period between 2001 and 2006, normalized Rate 6 average use has decreased by an average of 98.0 m^3 or 0.45% per year. With the current unpredictable migration trend, an average use factor that is solely based upon general service rate class is quite misleading when the total volume is in fact unchanged, all else being equal.

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

Figure 2
Rate 6 Normalized Average Use (m^3)



29. As in the past, trends in all of the Rate 6 sectors have been variable over time. Economic conditions, changes to building code as mentioned above, historical trend, and rate switching have always played a significant role in these sectors' average uses in addition to other similar factors that are impacting residential average uses. Rate 6 (general service rates) or contract customers often switch between rate classes or gas service plan types conditional upon meeting the minimum required volumes of 340,000 m^3 for Large Volume contracts.

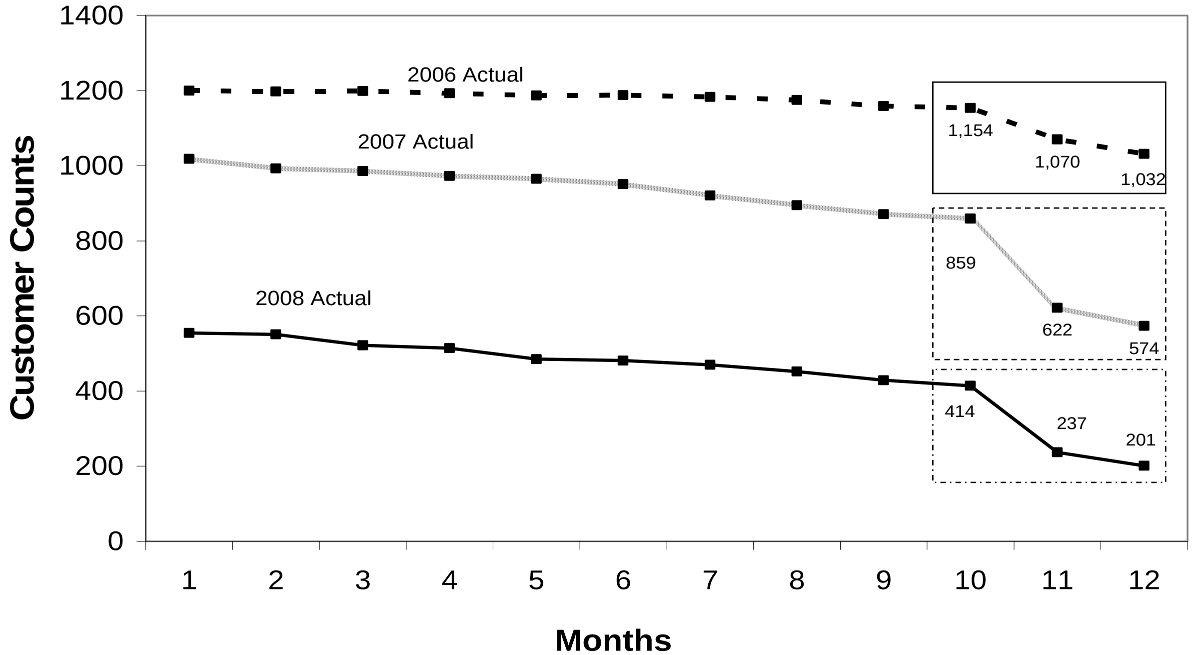
30. Customers typically sign a contract for one year, and the customer is made aware of the minimum bill penalties if the total consumption is below 340,000 m^3. Every year, account executives will review contracts with customers. If customers' prior year or future years' consumption does not meet the minimum threshold

requirement, customers would opt for switching to general service rates in order to avoid paying the minimum bill penalties. There are a number of reasons that the customers may not meet the minimum threshold, such as higher vacancy rates, warmer weather, customers embracing DSM or conservation initiatives, winding down industrial production, changes in production process to enhance efficiency, plant consolidation and fluctuation in product demand.

31. In addition to the factors mentioned above, the rate switching trend has been increased by new factors starting in the fall of 2006 as mentioned 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. These new factors are the introduction and enforcement of new large volume contracts along with Appendix A of the Company's Rate Handbook for each terminal location during 2006 as well as the rate design change for Rates 100 and 145 by requesting them to pay contract demand charges effective April 1, 2007.

32. In the past, large volume distribution contracts were not signed by the customers themselves as they were covered off under the Gas Transportation Agreements. Similarly, Rates 100 and 145 customers did not need to pay contract demand charges. In addition to these new factors, the phase-in changes to the upstream cost allocation since October 2004 and the rate redesign of Rate 6 in 2004 have been gradually reducing the cost difference between general service and contract rate classes for some customers. As a result, these changes also helped to increase the rate switching trend experienced during years 2006 to 2008. Figures 3 to 5 illustrate the occurrence of historic-high rate switching from contract rate class to Rate 6 during the contract renewal period since the fall of 2006.

Figure 3: Contract Market Unlock Customers Apartment Sector



Witnesses: I. Chan
T. Ladanyi

**Figure 4: Contract Market Unlock Customers
Commercial Sector**

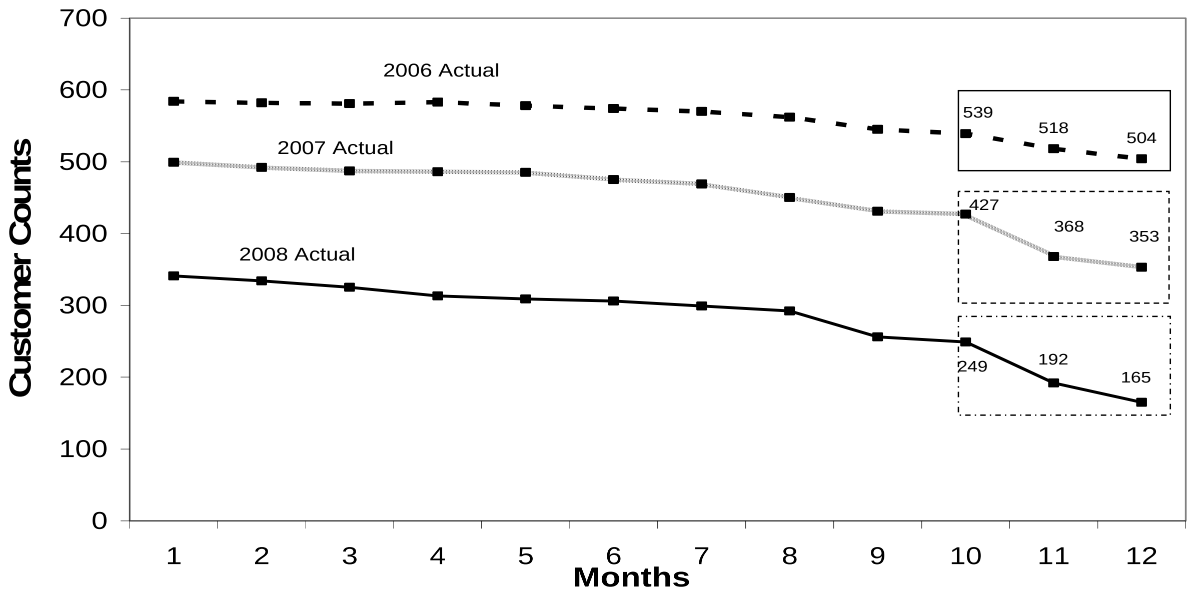
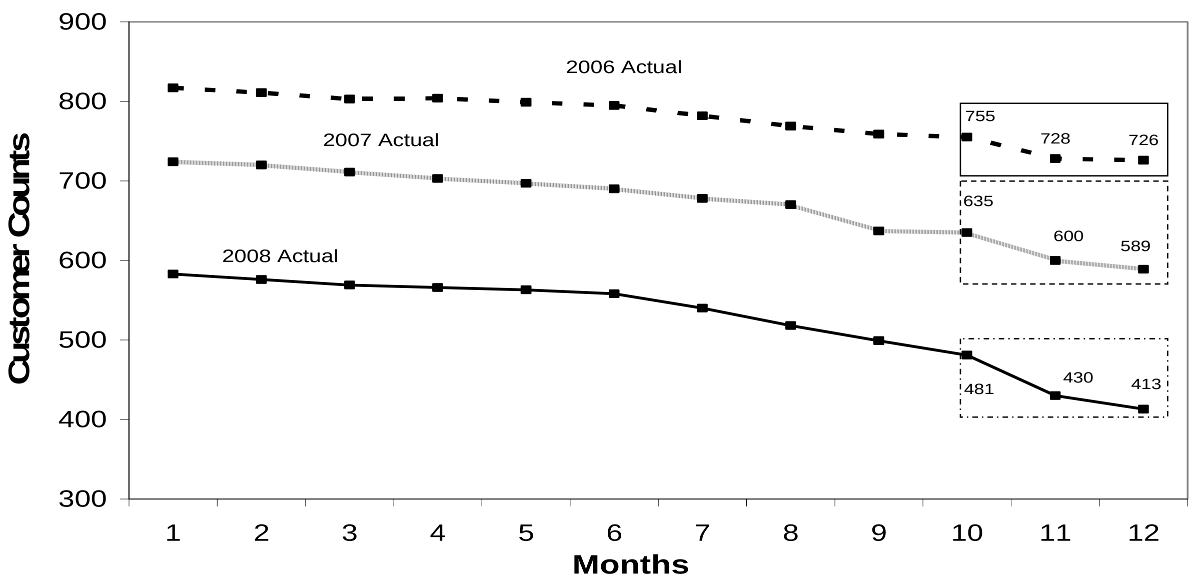


**Figure 5: Contract Market Unlock Customers
Industrial Sector**



Witnesses: I. Chan
T. Ladanyi

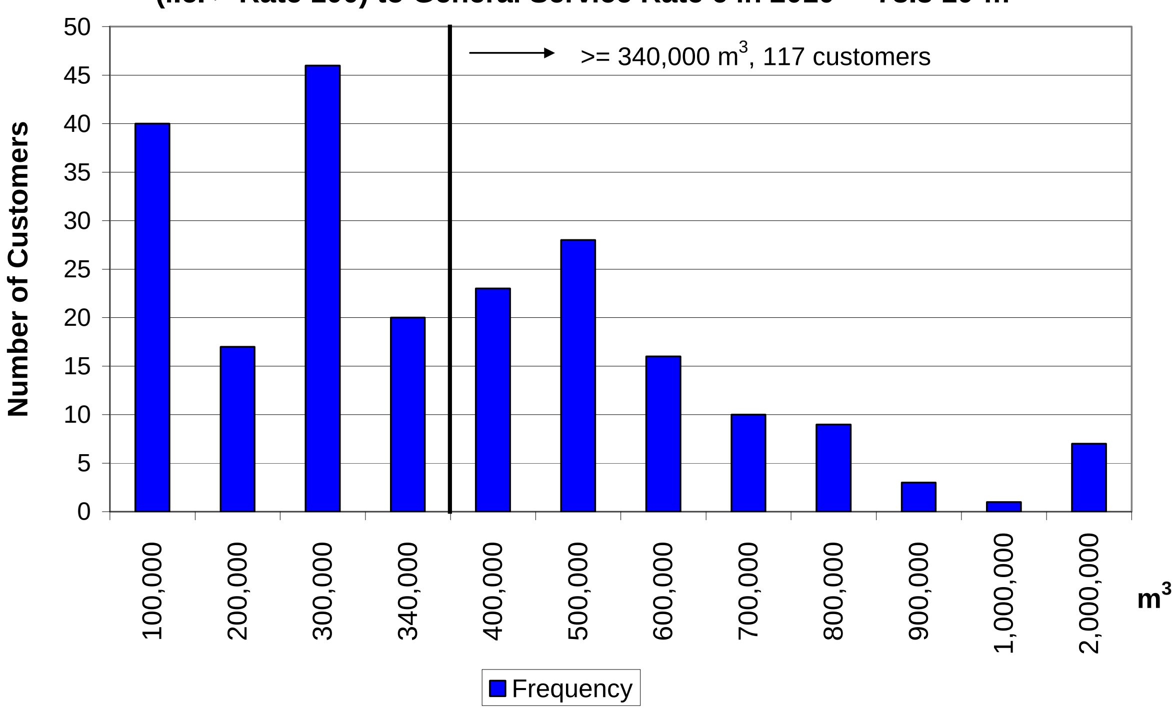
33. Over and above the factors mentioned above, another change to the rate design that was accepted in the Incentive Regulation Settlement Agreement at EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, pages 33 and 34, has further diminished the cost difference between general service and contract rate classes for remaining contract customers. Specifically, this rate design change reflects the implementation of increasing monthly customer charges for Rate 1 and Rate 6 on a revenue neutral basis by reducing variable charges accordingly and increasing both fixed and variable charges for other rate classes. Consequently, all existing Rate 100 customers will experience a reduction in rate impact by migrating from Rate 100 to Rate 6. In addition, these customers will no longer have to incur monthly fixed contract demand charges and minimum bill penalties in the situation of consuming gas less than their forecast or contracted volumes. This is especially important to customers who are currently facing volatile and unfavourable business environments. For instance, two large auto customers migrated to Rate 6 last year. This migration not only enables them to reduce energy expenses but also helps them to avoid paying either minimum bill penalties or monthly fixed contract demand charges when the plant is idle or during reduced production as experienced over the past several years.

34. The reason why these new rate switching factors are different from the previous years is that the rate switching that occurred in the past was primarily as a consequence of customers not meeting the annual threshold volume of 340,000 $m^{3.}$ The reason behind recent years' switching is that customers are receiving the financial benefits of migrating from their existing contract rate classes to general service Rate 6 even though their annual volume exceeds the volume threshold mentioned above. Figure 6 on the next page presents the frequency distribution of

the customers that are forecast to migrate from contract rate classes to general service Rate 6 (transfer gain only) between the 2010 Budget and the 2009 Bridge Year Estimate. Holding all other things constant, this increases the Rate 6 average use considerably as most of these customers consume more than 340,000 m^3 annually.

35. Based upon historical actual data to 2009, the regression model will not be able to predict the 2010 Budget rate switching for a heterogeneous customer mix that has different individual usage pattern as discussed above. Therefore, both the 2009 Estimate and the 2010 Budget volumes for these contract customers are layered onto the regression model's average use forecast.

Figure 6
Customer Migration from Contract Rate Class
(i.e. > Rate 100) to General Service Rate 6 in 2010 = 78.3 $10^6 m^3$



36. Tables 4 to 6 quantify the volumetric impact of the average use's 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 the Rate 6 volumes of 37.0 10^6m^3 is a consequence of rate switching from contract market customers, positive customer and employment growth, partially offset by the Company's DSM initiatives, other conservation initiatives originated by customers themselves or promoted by government programs or sourced from building code reflected in historical actual data, and higher gas prices in 2010 than in 2009.

37. Unlike the residential sector, the impact of the 2006 Building Code on Rate 6 average use was not incorporated into the 2009 Bridge Year Estimate. Even though both 2006 Building Code and further changes to this code also apply to both non-residential and larger residential buildings, there is insufficient information available from the Government of Ontario in order to apply the estimated energy savings to this heterogeneous customer rate class. All else being equal, the 2010 Rate 6 average use budget is on the high side. Further to this, similar to the residential sector the current Rate 6 volumetric forecast has not incorporated the potential unfavourable impact of declining purchasing power on the retail and manufacturing business upon the implementation of HST.

Table 4

Factors Influencing the Changes in Apartment Gas Consumption

Between 2010 Test Year Budget and 2009 Bridge Year Estimate (10^6m^3)

Factors	**Total Volume (10^6m^3)**
Customer Growth	1.3
DSM Initiatives	(12.3)
Economics, Gas Appliances (a)	18.4
Rate Switching - change in rate design (b)	39.8
Other Conservation (c)	(4.2)
Gas Prices	(1.4)
Total	41.6

(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 apartment's sector 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.

* Less than 50,000 m^3

Witnesses: I. Chan
T. Ladanyi

Table 5

Factors Influencing the Changes in Commercial Gas Consumption

Between 2010 Test Year Budget and 2009 Bridge Year Estimate (10^6m^3)

Factors	Total Volume (10^6m^3)
Customer Growth	6.4
DSM Initiatives	(11.2)
Economics, Gas Appliances (a)	6.7
Rate Switching - change in rate design (b)	13.9
Other Conservation (c)	(47.3)
Gas Prices	(0.4)
Growth Initiatives or Added Load (e)	0.2
Total	(31.7)

(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 commercial's sector 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.

* Less than 50,000 m^3

Witnesses: I. Chan
T. Ladanyi

Table 6

Factors Influencing the Changes in Industrial Gas Consumption

Between 2010 Test Year Budget and 2009 Bridge Year Estimate (10^6m^3)

Factors	Total Volume (10^6m^3)
Customer Growth	0.1
DSM Initiatives	(3.1)
Economics, Gas Appliances (a)	10.7
Rate Switching - change in rate design (b)	24.6
Other Conservation (c)	(5.1)
Gas Prices	(0.1)
Total	27.1

(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 industrial's sector 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.

* Less than 50,000 m^3

Witnesses: I. Chan
T. Ladanyi

Contract Market Volume Forecast Methodology

38. The volumes in the contract market were generated through an approved grass roots approach. Volumes are forecast on an individual customer basis by account executives through the consultation with customers during the budget process. Specifically, each account executive reviews the contract attributes (e.g., rate and plan type) with the new customer for each contract in order to ensure that each customer can meet its contracted rate class minimum volume and load factor requirements on a consistent basis. Then, the account executives incorporate all the customer's current economic or industry conditions for the customer's business, predicted economic or industry condition, budgeted degree days and the best known information about contract customers into the budget. The 2009 Bridge Year estimate for contract market customers has incorporated three months of 2009 information.

Contract Market Volumes: 2010 Budget

39. As mentioned in previous paragraphs, after removing the unfavourable rate switching from contract customers to general service rate class (or transfer losses) of 78.3 10^6m^3, the 2010 contract market volume budget is expected to be 30.1 10^6m^3 lower than the 2009 Estimate on a weather-normalized basis. This underage is primarily due to production decreases of 23.1 10^6m^3 driven by one large customer and a loss in load of 7.0 10^6m^3 relating to either plant closures and relocations outside the franchise area by industrial customers. Table 7 illustrates major variance drivers contributing to the reduction in contract market volumes between 2010 Budget and 2009 Estimate. Table 8 and Table 9 present the 2010 Budget lost customers or loss in load and migration to Rate 6 by trade group, respectively.

Table 7 - Comparison of Contract Market Volumes
2010 Budget and 2009 Bridge Year Estimate
(10^6m^3)

	Col. 1	Col. 2	Col. 3
	2010 Budget	2009 Bridge Year Estimate	2010 Budget Over (Under) 2009 Estimate
			(1-2)
Contract Market Total Gas Sales and Transportation Volumes	2,008.6	2,118.4	(109.8)
Major Variance Factors:			
Weather Normalization, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 4, Col. 4, Item No. 4			(1.4)
New Customers			0.0
Lost customers - Table 8			(7.0)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			0.0
Transfer losses - migration of customers from contract rates to general service rate 6			(78.3)
Wholesale customer - recovery in usage of one pulp and paper large customer			2.6
One large Petroleum customer's anticipation of maintenance (i.e. shutdown) and increase in gas prices in 2010			(20.5)
Impact of Economy on Auto Industries			(1.6)
Impact of Economy on Primary Metal & Machinery			(2.1)
Impact of Economy on Food, Beverage, Drug & Tobacco Industry			(1.7)
Others change in usage (e.g. change in production process, etc.)			0.1
Total Major Variance Factors:			(109.8)

Witnesses: I. Chan
T. Ladanyi

Table 8 - Lost Customers
Between 2010 Test Year Budget and 2009 Bridge Year Estimate

Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	1. Industrial Plant Closures	
(1)	Chemical and Chemical Products	(1.0)
(3)	Primary Metal & Machinery	(5.1)
(1)	Transportation Equipment	(0.9)
	2. Industrial Plant Relocations to Area Outside the Franchise	
(1)	Food, Beverage, Drug & Tobacco	(0.1)
	3. Total Lost Customers	
(6)		**(7.0)**

Witnesses: I. Chan
T. Ladanyi

Table 9 - Customer Migration from Contract Rate to Rate 6
Between 2010 Budget and 2009 Bridge Year Estimate

1. Customers that were migrated to Rate 6 in 2009

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)	
	(79)	Apartment	(21.4)	
	(6)	Business & Financial Service Industries	(2.0)	
	(1)	Chemical and Chemical Products	(0.6)	
	(1)	Construction Industries	0.0	**
	(3)	Education Services	(1.8)	
	(12)	Food, Beverage, Drug & Tobacco	(3.4)	
	(9)	Government Services	(3.4)	
	(1)	Greenhouses/Agriculture	(0.1)	
	(1)	Health, Social & Other Services	(0.3)	
	(9)	Hotels	(2.8)	
	(1)	Non-Metallic Mineral Products	0.0	**
	(1)	Plastic Products	(0.4)	
	(14)	Primary Metal & Machinery	(3.6)	
	(7)	Pulp & Paper	(1.6)	
	(1)	Recreational & Household Industries	(0.2)	
	(3)	Rubber Products	(1.7)	
	(2)	Transportation and Storage and Utilities	(0.3)	
	(11)	Transportation Equipment	(4.4)	
	(4)	Wholesale & Retail Trade	(1.0)	
	(1)	Wood & Furniture Industries	(0.6)	
Total	(167)		(49.6)	

2. Customers that will be migrated to Rate 6 in Fall 2009

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(39)	Apartment	(16.6)
	(1)	Electronics/High Tech	(0.4)
	(1)	Food, Beverage, Drug & Tobacco	(2.2)
	(2)	Primary Metal & Machinery	(2.0)
	(1)	Wholesale & Retail Trade	(0.7)
Total	(44)		(21.9)

3. Customers that will be migrated to Rate 6 in 2010

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(4)	Apartment	(1.8)
	(1)	Business & Financial Service Industries	(0.5)
	(1)	Rubber Products	(0.8)
	(1)	Textile Products	(0.5)
	(1)	Wholesale & Retail Trade	(0.7)
	(1)	Wood & Furniture Industries	(2.5)
Total	(9)		(6.8)
Grand Total	**(220)**		**(78.3)**

*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.

** Less than 50,000 m^3.

Witnesses: I. Chan
T. Ladanyi

40. Overall, the downturn in global economies, strong Canadian dollar, slumping vehicle sales for the large auto customers, global competition and rising labour, raw material, and energy costs are the major reasons cited by customers for closing a plant, relocating a plant to a lower cost area, consolidating several plants into few or one, and reducing production. These reasons were also the ongoing factors impacting the industrial sector in particular over the past several years. Once these plants were closed permanently or relocated to another franchise, this would be a permanent reduction to the Company's volumes.

41. Consistent with previous years' filings, the volume budget represents the best information at the time of completion. As the contract market budget was completed in May, the budget did not incorporate any plant closures or production decreases after this date, such as one large pulp and paper customer announced a production suspension indefinitely at several Canadian mills unexpectedly in mid-September. According to Statistics Canada, manufacturing sales in May were the lowest level since November 1998.[7] Plant shutdowns in the motor vehicle and primary metal industries accounted for most of the decline in May. Therefore, the risk of incurring larger industrial volume loss than budgeted is weighted heavily to the downside. Specifically, regression models cannot predict when a particular plant will be closed or production shift will be reduced. For instance, it certainly would not have predicted last Spring that the two large auto makers would declare bankruptcies this year.

[7] "Monthly Survey of Manufacturing." *The Daily*. Statistics Canada, May 2009. < http://www.statcan.gc.ca/daily-quotidien/090715/dq090715a-eng.htm>.
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Witnesses: I. Chan
T. Ladanyi

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

42. 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.

43. Appendix A, page 26 illustrates 14-Years of Normalized Actual vs. Board Approved volumes to evaluate accuracy of previous forecast for General Service average uses. Other than the unexpected, first time historic high natural gas prices that occurred in 2001 (Figure 1) that increased volumetric variances significantly, the average normalized percentage error variances between 2002 and 2007 were only 0.5% or 16 m^3 for Rate 1. Excluding the high and volatile gas prices periods of 2001, 2005 and 2006 and recession in 2008, average normalized percentage error variances between 2002 and 2004 as well as 2007 were merely 0.2% or 6 m^3 for Rate 1 use per customer.

44. Unexpected increase in gas prices in 2001, 2005 and 2006 as previously mentioned in the EB-2006-0034 proceeding explained why the corresponding Board Approved Budget numbers were higher than the Actuals. This also accounts for why the Board Approved Budget number for 2007 was lower than the Actual when gas prices were lower than forecast. In contrast, as noted in EB-2008-0219, Exhibit C, Tab 1, Schedule 5, the unexpected major financial crises primarily contributed to the shortfall in 2008 average uses.

45. As discussed in the previous section, unanticipated and unprecedented substantial customer migration from contract rates and general service Rate 6 driven by rate design changes since Fall 2006 was the primary factor that contributed to the Board Approved Budget number being lower than the Actual for Rate 6 in 2007 and 2008. Both account executives and customers were not aware of the rate design changes when developing the 2007 and 2008 budgets. During the peak contract renewal season (i.e., Fall), customers chose to migrate from contract rates to general service Rate 6 when this would reduce their energy expense.

46. Consequently, other than the unexpected, first time historic high natural gas prices that occurred in 2001 (Figure 1) and customer migration that increased volumetric variances significantly, the average normalized percentage error variances between 2002 and 2006 were only 0.2% or 51 m^3 for Rate 6.

47. Appendix A, page 28 illustrates 8 Years of Normalized Actual vs. Board Approved volumes for contract market customers to evaluate accuracy of previous forecast. As contract customer migration within contract rate classes will fluctuate year over year for various business reasons as indicated in the previous section, the historical accuracy of the volumes and reasonableness would be assessed on the total contract market volume level.

48. Excluding the uncontrollable factors as listed below, the average normalized percentage error variance between 2002 and 2004 was merely 0.2% or 8 10^6m^3. The uncontrollable factors are:
   - unexpected and historic high natural gas prices occurred in 2001 and 2006 that reduced gas consumption and caused plant closures along with other unfavourable business factors;

- unforeseen rate switching in 2007 of 330.0 10^6m^3 (EB-2008-0219, Exhibit B, Tab 1, Schedule 5, p. 29) and in 2008 of 103.9 10^6m^3 (EB-2009-0055, Exhibit B, Tab 3, Schedule 2, p. 3);
- unpredicted global economic downturn in 2008 and 2009.

49. As some large contract customers in the Company's franchise area are satellite locations or subsidiaries for multi-national corporations, decisions on their viabilities are being made from corporate headquarters. Consequently, the Company's local customers have forecast their volumetric needs on their best projections for their own company; they may not, however, be able to forecast their continued operation within the overall plan of their parent organization one year in advance for the test year budget.

50. This is evidenced by the unexpected plant closures or production decreases after the parent companies declared bankruptcies. This is one example that has occurred in recent years that the Company's local customers have forecast their volumetric needs on their best projections for their own company. They may not, however, be able to forecast their continued operation within the overall plan of their parent organization as decisions on their viabilities are being made from corporate headquarters.

Comparison of 2009 Estimate and 2008 Actual

51. The Estimate volumes of 11 057.0 10^6m^3 are forecast to be 850.5 10^6m^3 or 7.1% below the 2008 Actual of 11 907.5 10^6m^3. The unfavourable variance is primarily due to warmer winter weather forecast in 2009 than in 2008 Actual. On a weather-normalized basis the 2009 Bridge Year Estimate volumes are 434.7 10^6m^3 or 3.7% below the 2008 Actual. The decrease on a normalized basis is made up of an

increase in general service volumes of 528.8 10^6m^3 and a decrease in the contract market of 963.5 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 8 to 11.

52. The increase in the general service volumes of 595.1 10^6m^3 on a weather-normalized basis is primarily due to rate switching from contract rate to a general service rate class (or transfer gains) of 534.2 10^6m^3 as explained in previous sections, customer growth of 100.7 10^6m^3, and the Company's incremental added load initiatives of 0.8 10^6m^3, partially offset by decreases in general service average uses of 63.5 10^6m^3 along with a loss in load of 43.3 10^6m^3 relating to plant closures or relocations for Rate 6 Large Volume customers that were previously migrated from Contract Customers for the factors mentioned in previous sections.

53. The decrease in the contract market volumes of 963.5 10^6m^3 on a weather-normalized basis is primarily due to rate switching from contract rate to a general service rate class (or transfer gains) of 534.2 10^6m^3 as mentioned above as well as one large distributed energy customer migrated from Rate 115 to Rate 125 that has no distribution volume of 96.7 10^6m^3 effective July 1, 2008. After removing this migration, the 2009 contract market volumes are 332.6 10^6m^3 below 2008 actual. This negative volumetric variance is primarily driven by ongoing contract market customers' losses relating to either plant closures or consolidation (i.e., relocation outside the franchise area) of 61.8 10^6m^3, and production decreases in consequence of the economic downturn occurred since Fall 2008. Table 10 illustrates major variance drivers contributing to this reduction in contract market volumes by trade group. Tables 11 and 12 present new and lost customers, respectively.

Table 10 - Comparison of Contract Market Volumes
2009 Bridge Year Estimate and 2008 Actual
(10^6m^3)

	Col. 1	Col. 2	Col. 3
	2009 Bridge Year Estimate	2008 Actual	2009 Estimate Over (Under) 2008 Actual (1-2)
Contract Market Total Gas Sales and Transportation Volumes	2,118.4	3,101.5	(983.1)
Major Variance Factors:			
Weather Normalization, Appendix A, Page 10, Col. 4, Item. 4			(19.6)
Impact of economy on one landfill gas customer			(0.3)
New Customers			3.0
One large distributed energy customer migrated from rate 115 to unbundled rate class (rate 125) in July 2008			(96.7)
Lost customers			(61.8)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			8.3
Transfer losses - migration of customers from contract rates to general service rate 6			(542.5)
Wholesale customer - economy and anticipation of increase in gas prices by large pulp and paper customers			(26.2)
One large Petroleum customer - economy and anticipation of increase in gas prices			(25.6)
Impact of economy on Auto Industries			(30.5)
Impact of fire, price spread between Hydro and Gas, and economy on one large Power Generation customer			(9.7)
Impact of economy, price spread between Hydro and Gas, and business competition on two large Power Generation customers			(24.2)
Impact of economy on one large Distributed Energy customer			(10.3)
Impact of economy on Chemical and Chemical Products Industry			(17.6)
Impact of economy on Food, Beverage, Drug & Tobacco Industry			(12.0)
Impact of economy on Non-Metallic Mineral Products Industry			(40.0)
Impact of economy on two large Primary Metal & Machinery customers			(32.4)
Impact of economy on other Primary Metal & Machinery customers			(12.7)
Impact of Canadian dollar, economy and global competition on Pulp & Paper Industry			(23.3)
Others change in usage (e.g. change in production process, economy, energy conservation initiatives, etc.)			(9.0)
Total Major Variance Factors:			(983.1)

Table 11 - New Customers
Between 2009 Bridge Year Estimate and 2008 Actual

Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
1	Asphalt	0.5
1	Health, Social & Other Services	2.5
2		**3.0**

Witnesses: I. Chan
T. Ladanyi

Table 12 - Lost Customers
Between 2009 Bridge Year Estimate and 2008 Actual

Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
1. Industrial Plant or Building Closures		
(2)	Chemical and Chemical Products	(1.0)
(1)	Health, Social & Other Services	(0.9)
(1)	Non-Metallic Mineral Products	(17.6)
(5)	Primary Metal & Machinery	(4.4)
(2)	Pulp & Paper	(18.4)
(1)	Rubber Products	(1.7)
(3)	Transportation Equipment	(6.3)
2. Industrial Plant Relocations to Area Outside the Franchise		
Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
(1)	Chemical and Chemical Products	(0.4)
(2)	Construction Industries	(0.8)
(5)	Food, Beverage, Drug & Tobacco	(9.6)
(1)	Primary Metal & Machinery	(0.1)
(1)	Rubber Products	(0.7)
3. Total Lost Customers		
(25)		**(61.8)**

Comparison of 2009 Estimate and 2009 Board Approved

54. The Estimate volumes of 11 057.0 10^6m^3 are forecast to be 342.8 10^6m^3 or 3.0% below the 2009 Board Approved Budget of 11 399.8 10^6m^3. The decrease on a normalized basis is made up of a decrease in general service volumes of 144.6 10^6m^3 and a decrease in the contract market of 198.2 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 12 to 14.

Witnesses: I. Chan
T. Ladanyi

55. The decrease in the general service volumes of 144.6 10^6m^3 is primarily due to net rate switching losses from a general service rate class to contract rate class (or transfer losses) of 84.5 10^6m^3 mainly due to timing, customer losses of 72.8 10^6m^3 primarily driven by plant closures or relocations of Rate 6 Large Volume customers of 63.0 10^6m^3 that were previously migrated from contract customers and lower residential customers added than expected of 9.7 10^6m^3 , decreases in residential average uses of 27.5 10^6m^3 for the factors mentioned in previous sections, partially offset by an increase in Rate 6 average use of 40.9 10^6m^3 resulting from customer migration from contract rate class that has annual volume higher than 340,000 m^3 as explained in previous sections.

56. The decrease in the contract market volumes of 198.2 10^6m^3 is primarily due to ongoing contract market customers' losses relating to either plant closures or consolidation (i.e., relocation outside the franchise area) of 53.7 10^6m^3 as shown on Table 15 and production decreases in consequence of the economic downturn occurred since Fall 2008, partially offset by new customers of 3.8 10^6m^3, and net rate switching gain from a general service rate class to contract rate (or transfer gains) of 84.5 10^6m^3 mainly due to timing as shown on Tables 13 and 14. Table 17 illustrates major variance drivers contributing to this reduction in contract market volumes by trade group.

57. This reduction in volumes is not unexpected in the wake of the rapidly deteriorating economic conditions that began in October 2008 which contributed to the short fall in general service average uses and contract market volumes as noted in EB-2009-0055, Exhibit B, Tab 3, Schedule 2, Page 3 and Exhibit C, Tab 1, Schedule 5. As 2009 Board Approved Budget was developed during early Summer 2008 prior to the occurrence of recession that were not experienced recently, the

Budget would not reflect the unanticipated surge in plant closures and business bankruptcies, 26-year low in Canadian consumer confidence,[8] and unemployment rate reached to a 15-year high of 9.4 per cent in the Spring.[9] For instance, no analyst in Spring 2008 would have predicted the two large automakers would declare bankruptcies this year.

[8] "Canadian consumer confidence retreats to 1982 level." CBC News, Oct. 17, 2008. <http://www.cbc.ca/canada/toronto/story/2008/10/17/confidence.html>.
[9] "Labour Force Survey." *The Daily*. Statistics Canada, May 2009. <http://www.statcan.gc.ca/daily-quotidien/090605/dq090605a-eng.htm>.

Table 13 - Customer Migration from Contract Rate to Rate 6
Between 2009 Bridge Year Estimate and 2009 Board Approved Budget

1. Customers that were already migrated to Rate 6 in 2009
- due to both rate design changes and production cuts

	Number of Customers*	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	(6)	Apartment	(3.3)
	(1)	Chemical and Chemical Products	(1.1)
	(4)	Food, Beverage, Drug & Tobacco	(1.8)
	(1)	Government Services	(0.6)
	(3)	Health, Social & Other Services	(2.7)
	(1)	Non-Metallic Mineral Products	(2.4)
	(7)	Primary Metal & Machinery	(9.3)
	(1)	Rubber Products	(0.6)
	(4)	Transportation Equipment	(13.8)
Total	(28)		(35.6)

2. Customers that will be migrated to Rate 6 in Fall 2009
- due to both rate design and production cuts

	Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	(1)	Apartment	(0.3)
Total	(1)		(0.3)
Grand Total	**(29)**		**(35.9)**

*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.

Witnesses: I. Chan
T. Ladanyi

Table 14 - Customer Migration from Rate 6 to Contract
Between 2009 Bridge Year Estimate and 2009 Board Approved Budget

1. Customers were already migrated to Rate 6 in 2009**

	Number of Customers*	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	79	Apartment	21.2
	6	Business & Financial Service Industries	2.0
	1	Chemical and Chemical Products	0.6
	3	Education Services	1.8
	9	Food, Beverage, Drug & Tobacco	3.2
	9	Government Services	3.3
	1	Greenhouses/Agriculture	0.1
	9	Hotels	2.8
	2	Non-Metallic Mineral Products	0.9
	1	Plastic Products	0.4
	11	Primary Metal & Machinery	3.0
	7	Pulp & Paper	1.6
	1	Recreational & Household Industries	0.2
	3	Rubber Products	1.7
	2	Transportation and Storage and Utilities	0.3
	8	Transportation Equipment	3.3
	4	Wholesale & Retail Trade	1.0
	1	Wood & Furniture Industries	0.6
Total	158		47.9

2. Customers that will be migrated to Rate 6 in Fall 2009**

	Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	39	Apartment	16.6
	1	Electronics/High Tech	0.4
	1	Food, Beverage, Drug & Tobacco	2.1
	2	Primary Metal & Machinery	2.1
	1	Wholesale & Retail Trade	0.7
Total	44		22.1

3. Customers that will be migrated to Rate 6 in 2010

	Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	4	Apartment	1.7
	1	Business & Financial Service Industries	0.5
	1	Rubber Products	0.8
	1	Textile Products	0.5
	1	Wholesale & Retail Trade	0.7
	1	Wood & Furniture Industries	2.4
Total	9		6.7

Witnesses: I. Chan
T. Ladanyi

4. Customers stayed at contract even though they were beneficial to migrate to rate 6

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	1	All Other Industrial	1.6
	11	Apartment	6.3
	1	Asphalt	0.6
	4	Chemical and Chemical Products	4.7
	3	Food, Beverage, Drug & Tobacco	4.9
	3	Government Services	7.3
	2	Greenhouses/Agriculture	1.6
	1	Health, Social & Other Services	0.9
	3	Hotels	3.3
	2	Primary Metal & Machinery	1.2
	2	Pulp & Paper	3.9
	1	Textile Products	0.9
	1	Transportation Equipment	2.6
	1	Wood & Furniture Industries	0.6
Total	36		40.3

5. Customers stayed at contract temporarily due to change of ownership

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	2	Apartment	1.1
	1	Asphalt	1.3
	1	Construction Industries	1.0
Total	4		3.4
Grand Total	**251**		**120.4**

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

**Based upon latest actual account information that was not incorporated in 2009 Estimate but was already incorporated in 2010 Forecast.

Witnesses: I. Chan
T. Ladanyi

Table 15 - Lost Customers
Between 2009 Bridge Year Estimate and 2009 Test Year Budget

1. Industrial Plant or Building Closures

Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
(2)	Chemical and Chemical Products	(1.2)
(1)	Health, Social & Other Services	(1.5)
(1)	Non-Metallic Mineral Products	(30.2)
(4)	Primary Metal & Machinery	(4.2)
(1)	Rubber Products	(2.5)
(3)	Transportation Equipment	(10.8)

2. Industrial Plant Relocations to Area Outside the Franchise

Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
(1)	Chemical and Chemical Products	(1.0)
(1)	Food, Beverage, Drug & Tobacco	(1.1)
(1)	Rubber Products	(1.3)

3. Total Lost Customers

(15)		**(53.7)**

Table 16 - New Customers
Between 2009 Bridge Year Estimate and 2009 Test Year Budget

Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
1	Asphalt	0.8
1	Health, Social & Other Services	3.0
2		**3.8**

Witnesses: I. Chan
T. Ladanyi

Table 17 - Comparison of Contract Market Volumes
2009 Bridge Year Estimate and 2009 Board Approved Budget
(10^6m^3)

	Col. 1	Col. 2	Col. 3
	2009 Bridge Year Estimate	2009 Budget	2009 Estimate Over (Under) 2009 Budget
			(1-2)
Contract Market Total Gas Sales and Transportation Volumes	2,118.4	2,316.6	(198.2)
Major Variance Factors:			
Weather Normalization			0.0
Impact of economy on one landfill gas customer			(10.7)
New Customers			3.8
Lost customers			(53.7)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			120.4
Transfer losses - migration of customers from contract rates to general service rate 6			(35.9)
Wholesale customer - impact of lower gas prices than oil, partially offset by economic downturn			5.5
Impact of economy on Auto Industries			(32.5)
Impact of fire, price spread between Hydro and Gas, and economy on one large Power Generation customer			(25.5)
Impact of economy, price spread between Hydro and Gas, and competition on three large Power Generation and two Distributed Energy customers			(29.3)
Impact of economy on Greenhouses/Agriculture and Chemical and Chemical Products Industry			(17.2)
Impact of economy on Non-Metallic Mineral Products			(35.2)
Impact of economy on one large Petroleum customer, partially offset by lower gas prices than oil			18.9
Impact of economy on two large Primary Metal & Machinery customers			(41.4)
Impact of economy on other Primary Metal & Machinery customers			(18.2)
Impact of Canadian dollar, economy and global competition on Pulp & Paper industry			(18.9)
Impact of economy on Food, Beverage, Drug & Tobacco Inudstry			(8.0)
Impact of economy on Asphalt, Rubber & Plastic Industry			(8.9)
Impact of energy conservation initiatives on Government Services			(8.0)
Others change in usage (e.g. economy, energy conservation initiatives, etc.)			(3.4)
Total Major Variance Factors:			(198.2)

Weather Normalization Methodology

58. The weather normalization methodology embraced by the Company has been approved by the Board and utilized for more than ten years. Consistent with the previous rate case, this section explains the Board approved normalization methodology of normalizing actual consumption for each of the general service rate classes and uses an example to describe how the normalization is done.

59. General Service normalization is conducted on customers at a group level. The Company's General Service customers are grouped together into homogenous classes of gas usage within the six 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 follows. An example of the methodology is illustrated below.

60. 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.

61. In the EBRO 465 Decision with Reasons, paragraph 3.1.16 states that the Board accepted the Company's weather normalization methodology and directed the Company to further investigate methods to more effectively segregate its weather sensitive and non-weather sensitive loads. A more effective segregation of load and an enhanced weather normalization methodology that included changing summer base load definition to the average of July and August consumption,

performing calculations using new base load/heating load split and include September as a heating load month, was proposed in EBRO 473 and the Board accepted this change in methodology.

62. 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. The reason was that results from load research indicated that this 18^{O}C balance point assumption was not valid due to technological and building standard environment. The basic conclusion of the research was that an average balance point value for Central, Niagara, and Eastern weather zones are 14.8^{O}C, 15.3^{O}C and 14.6^{O}C, respectively. That means the new normalization approach only normalizes heating load in the Central weather zone if the temperature falls below 14.8^{O}C.

63. In addition, this proposed new normalizing technique has been very 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 and out of the winter period can fluctuate significantly depending on the length of a seasonably warm or cold cycle.

64. As stated in the Decision with Reasons, the Board found the Company's proposals to implement an improved model for heating load analysis when estimating volumetric forecasts was reasonable and acceptable. All intervenors accepted the Company’s proposals during the settlement process. They all felt that the proposed

changes were a significant improvement over the balance point traditionally used at 18^{o}C or 65 ^{o}F.

65. 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 heating load 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. For example, a large volume customer with interruptible contract may be required to reduce or to completely eliminate or curtail the use of gas to balance the Company's gas supply and demand requirements under extreme or peak weathers. Therefore, the actual volumes used by customers would have been lower than budgeted and must be increased to the normal level assumed in the budget.

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2010 BUDGET

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	
General Service				
1.1.1	Rate 1 - Sales	1 152 358	3 030.6	
1.1.2	Rate 1 - T-Service	620 341	1 615.5	
1.1	Total Rate 1	1 772 699	4 646.1	
1.2.1	Rate 6 - Sales	108 729	1 990.4	
1.2.2	Rate 6 - T-Service	49 528	2 445.3	
1.2	Total Rate 6	158 257	4 435.7	
1.3.1	Rate 9 - Sales	24	1.4	
1.3.2	Rate 9 - T-Service	3	0.3	
1.3	Total Rate 9	27	1.7	
1.	Total General Service Sales & T-Service	1 930 983	9 083.5	
Contract Sales				
2.1	Rate 100	0	0.0	
2.2	Rate 110	36	43.9	
2.3	Rate 115	1	4.4	
2.4	Rate 135	4	5.9	
2.5	Rate 145	12	25.2	
2.6	Rate 170	6	79.7	
2.7	Rate 200	1	156.1	
2.	Total Contract Sales	60	315.2	
Contract T-Service				
3.1	Rate 100	0	0.0	
3.2	Rate 110	203	518.8	
3.3	Rate 115	41	421.2	
3.4	Rate 125	4	0.0	*
3.5	Rate 135	35	52.2	
3.6	Rate 145	167	196.8	
3.7	Rate 170	25	463.4	
3.8	Rate 300	10	41.0	
3.9	Rate 315	0	0.0	
3.	Total Contract T-Service	485	1 693.4	
4.	Total Contract Sales & T-Service	545	2 008.6	
5.	Total	1 931 528	11 092.1	

* There is no distribution volume for Rate 125 customers.

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2010 BUDGET AND 2009 BRIDGE YEAR ESTIMATE

Item No.		Col. 1 2010 Budget	Col. 2 2009 Bridge Year Estimate	Col. 3 2010 Budget Over (Under) 2009 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 152 358	1 131 079	21 279
1.1.2	Rate 1 - T-Service	620 341	611 628	8 713
1.1	Total Rate 1	1 772 699	1 742 707	29 992
1.2.1	Rate 6 - Sales	108 729	108 689	40
1.2.2	Rate 6 - T-Service	49 528	48 630	898
1.2	Total Rate 6	158 257	157 319	938
1.3.1	Rate 9 - Sales	24	24	0
1.3.2	Rate 9 - T-Service	3	3	0
1.3	Total Rate 9	27	27	0
1.	Total General Service Sales & T-Service	1 930 983	1 900 053	30 930
Contract Sales				
2.1	Rate 100	0	30	(30)
2.2	Rate 110	36	35	1
2.3	Rate 115	1	1	0
2.4	Rate 135	4	4	0
2.5	Rate 145	12	12	0
2.6	Rate 170	6	6	0
2.7	Rate 200	1	1	0
2.	Total Contract Sales	60	89	(29)
Contract T-Service				
3.1	Rate 100	0	64	(64)
3.2	Rate 110	203	208	(5)
3.3	Rate 115	41	41	0
3.4	Rate 125	4	3	1
3.5	Rate 135	35	35	0
3.6	Rate 145	167	168	(1)
3.7	Rate 170	25	25	0
3.8	Rate 300	10	10	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	485	554	(69)
4.	Total Contract Sales & T-Service	545	643	(98)
5.	Total	1 931 528	1 900 696	30 832

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2010 BUDGET AND 2009 BRIDGE YEAR ESTIMATE
(10^6m^3)

Item No.		Col. 1 2010 Budget	Col. 2 2009 Bridge Year Estimate	Col. 3 2010 Budget Over (Under) 2009 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 030.6	2 972.4	58.2
1.1.2	Rate 1 - T-Service	1 615.5	1 592.0	23.5
1.1	Total Rate 1	4 646.1	4 564.4	81.7
1.2.1	Rate 6 - Sales	1 990.4	1 992.4	(2.0)
1.2.2	Rate 6 - T-Service	2 445.3	2 380.0	65.3
1.2	Total Rate 6	4 435.7	4 372.4	63.3
1.3.1	Rate 9 - Sales	1.4	1.5	(0.1)
1.3.2	Rate 9 - T-Service	0.3	0.3	0.0
1.3	Total Rate 9	1.7	1.8	(0.1)
1.	Total General Service Sales & T-Service	9 083.5	8 938.6	144.9
Contract Sales				
2.1	Rate 100	0.0	12.9	(12.9)
2.2	Rate 110	43.9	45.6	(1.7)
2.3	Rate 115	4.4	4.3	0.1
2.4	Rate 135	5.9	5.8	0.1
2.5	Rate 145	25.2	25.2	0.0
2.6	Rate 170	79.7	78.5	1.2
2.7	Rate 200	156.1	156.8	(0.7)
2.	Total Contract Sales	315.2	329.1	(13.9)
Contract T-Service				
3.1	Rate 100	0.0	59.6	(59.6)
3.2	Rate 110	518.8	529.0	(10.2)
3.3	Rate 115	421.2	429.1	(7.9)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	52.2	52.1	0.1
3.6	Rate 145	196.8	197.7	(0.9)
3.7	Rate 170	463.4	480.8	(17.4)
3.8	Rate 300	41.0	41.0	0.0
3.9	Rate 315	0.0 *	0.0	0.0
3.	Total Contract T-Service	1 693.4	1 789.3	(95.9)
4.	Total Contract Sales & T-Service	2 008.6	2 118.4	(109.8)
5.	Total	11 092.1	11 057.0	35.1

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2010 BUDGET AND 2009 BRIDGE YEAR ESTIMATE
($10^6 m^3$)

Item No.		Col. 1 2010 Budget	Col. 2 2009 Bridge Year Estimate	Col. 3 2010 Budget Over (Under) 2009 Estimate (1-2)	Col. 4 2009* Adjustments	Col. 5 2010 Budget Over (Under) 2009 Estimate with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 030.6	2 972.4	58.2	18.1	40.1
1.1.2	Rate 1 - T-Service	1 615.5	1 592.0	23.5	9.4	14.1
1.1	Total Rate 1	4 646.1	4 564.4	81.7	27.5	54.2
1.2.1	Rate 6 - Sales	1 990.4	1 992.4	(2.0)	11.8	(13.8)
1.2.2	Rate 6 - T-Service	2 445.3	2 380.0	65.3	14.5	50.8
1.2	Total Rate 6	4 435.7	4 372.4	63.3	26.3	37.0
1.3.1	Rate 9 - Sales	1.4	1.5	(0.1)	0.0	(0.1)
1.3.2	Rate 9 - T-Service	0.3	0.3	0.0	0.0	0.0
1.3	Total Rate 9	1.7	1.8	(0.1)	0.0	(0.1)
1.	Total General Service Sales & T-Service	9 083.5	8 938.6	144.9	53.8	91.1
Contract Sales						
2.1	Rate 100	0.0	12.9	(12.9)	0.1	(13.0)
2.2	Rate 110	43.9	45.6	(1.7)	0.0 **	(1.7)
2.3	Rate 115	4.4	4.3	0.1	0.0 **	0.1
2.4	Rate 135	5.9	5.8	0.1	0.0	0.1
2.5	Rate 145	25.2	25.2	0.0	0.1	(0.1)
2.6	Rate 170	79.7	78.5	1.2	0.1	1.1
2.7	Rate 200	156.1	156.8	(0.7)	(3.3)	2.6
2.	Total Contract Sales	315.2	329.1	(13.9)	(3.0)	(10.9)
Contract T-Service						
3.1	Rate 100	0.0	59.6	(59.6)	0.3	(59.9)
3.2	Rate 110	518.8	529.0	(10.2)	0.2	(10.4)
3.3	Rate 115	421.2	429.1	(7.9)	0.0 **	(7.9)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	52.2	52.1	0.1	0.0	0.1
3.6	Rate 145	196.8	197.7	(0.9)	0.4	(1.3)
3.7	Rate 170	463.4	480.8	(17.4)	0.7	(18.1)
3.8	Rate 300	41.0	41.0	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	1 693.4	1 789.3	(95.9)	1.6	(97.5)
4.	Total Contract Sales & T-Service	2 008.6	2 118.4	(109.8)	(1.4)	(108.4)
5.	Total	11 092.1	11 057.0	35.1	52.4	(17.3)

* Note: Weather normalization adjustments have been made to the 2009 Bridge Year Estimate utilizing the 2010 Budget degree days in order to place the two years on a comparable basis.

** Less than 50,000 m^3.

COMPARISON OF GAS SALES AND TRANSPORTATION VOLUME BY RATE CLASS 2010 BUDGET AND 2009 BRIDGE YEAR ESTIMATE

(10^6m^3)

Item No.		Col. 1 2010 Budget	Col. 2 2009 Bridge Year Estimate	Col. 3 2010 Budget Over (Under) 2009 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	3 030.6	2 972.4	58.2	(17.2)	18.1	56.8	0.0	0.0	0.0	0.5
1.1.2	Rate 1 - T-Service	1 615.5	1 592.0	23.5	(8.7)	9.4	22.8	0.0	0.0	0.0	0.0
1.1	Total Rate 1	4 646.1	4 564.4	81.7	(25.9)	27.5	79.6	0.0	0.0	0.0	0.5
1.2.1	Rate 6 - Sales	1 990.4	1 992.4	(2.0)	(34.7)	11.8	7.8	12.9	0.0	0.0	0.2
1.2.2	Rate 6 - T-Service	2 445.3	2 380.0	65.3	(14.6)	14.5	0.0	65.4	0.0	0.0	0.0
1.2	Total Rate 6	4 435.7	4 372.4	63.3	(49.3)	26.3	7.8	78.3	0.0	0.0	0.2
1.3.1	Rate 9 - Sales	1.4	1.5	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.3	Total Rate 9	1.7	1.8	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0
1.	Total General Service	9 083.5	8 938.6	144.9	(75.3)	53.8	87.4	78.3	0.0	0.0	0.7
Contract Sales											
2.1	Rate 100	0.0	12.9	(12.9)	0.0	0.1	0.0	0.0	(12.9)	(0.1)	0.0
2.2	Rate 110	43.9	45.6	(1.7)	(1.2)	0.0 *	0.0	0.0	(0.5)	0.0	0.0
2.3	Rate 115	4.4	4.3	0.1	0.1	0.0 *	0.0	0.0	0.0	0.0	0.0
2.4	Rate 135	5.9	5.8	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
2.5	Rate 145	25.2	25.2	0.0	(0.1)	0.1	0.0	0.0	0.0	0.0	0.0
2.6	Rate 170	79.7	78.5	1.2	1.1	0.1	0.0	0.0	0.0	0.0	0.0
2.7	Rate 200	156.1	156.8	(0.7)	2.6	(3.3)	0.0	0.0	0.0	0.0	0.0
2.	Total Contract Sales	315.2	329.1	(13.9)	2.6	(3.0)	0.0	0.0	(13.4)	(0.1)	0.0
Contract T-Service											
3.1	Rate 100	0.0	59.6	(59.6)	0.0	0.3	0.0	0.0	(59.9)	0.0	0.0
3.2	Rate 110	518.8	529.0	(10.2)	(1.2)	0.2	0.0	0.0	(7.2)	(2.0)	0.0
3.3	Rate 115	421.2	429.1	(7.9)	(7.9)	0.0 *	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	52.2	52.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
3.6	Rate 145	196.8	197.7	(0.9)	(0.8)	0.4	0.0	0.0	(0.5)	0.0	0.0
3.7	Rate 170	463.4	480.8	(17.4)	(13.2)	0.7	0.0	0.0	0.0	(4.9)	0.0
3.8	Rate 300	41.0	41.0	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	1 693.4	1 789.3	(95.9)	(23.0)	1.6	0.0	0.0	(67.6)	(6.9)	0.0
4.	Total Contract Sales & T-Service	2 008.6	2 118.4	(109.8)	(20.4)	(1.4)	0.0	0.0	(81.0)	(7.0)	0.0
5.	Total	11 092.1	11 057.0	35.1	(95.7)	52.4	87.4	78.3	(81.0)	(7.0)	0.7

* Less than 50,000 m^3.

The principal reasons for the variances contributing to the weather normalized decrease of 17.3 10^6m^3 in the 2010 Budget over the 2009 Bridge Year Estimate are as follows:

1. The volumetric increase of 54.2 10^6m^3 in Rate 1 is due to customer growth of 79.6 10^6m^3; partially offset by a lower average use per customer totalling 25.4 10^6m^3;

2. The volumetric increase of 37.0 10^6m^3 in Rate 6 is due to customer growth of 7.8 10^6m^3 and net customer migration from Contract Sales and T-Service of 78.3 10^6m^3; partially offset by a lower average use per customer totalling 49.1 10^6m^3;

3. The volumetric decrease of 0.1 10^6m^3 in Rate 9 is due to a lower average use per station of 0.1 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 108.4 10^6m^3 is due to decreases in the apartment sector of 39.8 10^6m^3, the commercial sector of 11.9 10^6m^3 and the industrial sector of 59.3 10^6m^3; partially offset by an increase in Rate 200 of 2.6 10^6m^3. This decrease is primarily attributable to net customer migration to General Service of 78.3 10^6m^3 as stated above.

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2009 BRIDGE YEAR ESTIMATE

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)
General Service			
1.1.1	Rate 1 - Sales	1 131 079	2 972.4
1.1.2	Rate 1 - T-Service	611 628	1 592.0
1.1	Total Rate 1	1 742 707	4 564.4
1.2.1	Rate 6 - Sales	108 689	1 992.4
1.2.2	Rate 6 - T-Service	48 630	2 380.0
1.2	Total Rate 6	157 319	4 372.4
1.3.1	Rate 9 - Sales	24	1.5
1.3.2	Rate 9 - T-Service	3	0.3
1.3	Total Rate 9	27	1.8
1.	Total General Service Sales & T-Service	1 900 053	8 938.6
Contract Sales			
2.1	Rate 100	30	12.9
2.2	Rate 110	35	45.6
2.3	Rate 115	1	4.3
2.4	Rate 135	4	5.8
2.5	Rate 145	12	25.2
2.6	Rate 170	6	78.5
2.7	Rate 200	1	156.8
2.	Total Contract Sales	89	329.1
Contract T-Service			
3.1	Rate 100	64	59.6
3.2	Rate 110	208	529.0
3.3	Rate 115	41	429.1
3.4	Rate 125	3	0.0 *
3.5	Rate 135	35	52.1
3.6	Rate 145	168	197.7
3.7	Rate 170	25	480.8
3.8	Rate 300	10	41.0
3.9	Rate 315	0	0.0
3.	Total Contract T-Service	554	1 789.3
4.	Total Contract Sales & T-Service	643	2 118.4
5.	Total	1 900 696	11 057.0

* There is no distribution volume for Rate 125 customers.

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2009 BRIDGE YEAR ESTIMATE AND 2008 ACTUAL

Item No.		Col. 1 2009 Bridge Year Estimate	Col. 2 2008 Actual	Col. 3 2009 Estimate Over (Under) 2008 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 131 079	1 078 118	52 961
1.1.2	Rate 1 - T-Service	611 628	630 402	(18 774)
1.1	Total Rate 1	1 742 707	1 708 520	34 187
1.2.1	Rate 6 - Sales	108 689	104 000	4 689
1.2.2	Rate 6 - T-Service	48 630	51 207	(2 577)
1.2	Total Rate 6	157 319	155 207	2 112
1.3.1	Rate 9 - Sales	24	26	(2)
1.3.2	Rate 9 - T-Service	3	3	0
1.3	Total Rate 9	27	29	(2)
1.	Total General Service Sales & T-Service	1 900 053	1 863 756	36 297
Contract Sales				
2.1	Rate 100	30	129	(99)
2.2	Rate 110	35	34	1
2.3	Rate 115	1	1	0
2.4	Rate 135	4	3	1
2.5	Rate 145	12	11	1
2.6	Rate 170	6	5	1
2.7	Rate 200	1	1	0
2.	Total Contract Sales	89	184	(95)
Contract T-Service				
3.1	Rate 100	64	580	(516)
3.2	Rate 110	208	209	(1)
3.3	Rate 115	41	48	(7)
3.4	Rate 125	3	3	0
3.5	Rate 135	35	37	(2)
3.6	Rate 145	168	164	4
3.7	Rate 170	25	29	(4)
3.8	Rate 300	10	10	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	554	1 080	(526)
4.	Total Contract Sales & T-Service	643	1 264	(621)
5.	Total	1 900 696	1 865 020	35 676

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2009 BRIDGE YEAR ESTIMATE AND 2008 ACTUAL
(10^6m^3)

Item No.		Col. 1 2009 Bridge Year Estimate	Col. 2 2008 Actual	Col. 3 2009 Estimate Over (Under) 2008 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	2 972.4	2 985.6	(13.2)
1.1.2	Rate 1 - T-Service	1 592.0	1 738.7	(146.7)
1.1	Total Rate 1	4 564.4	4 724.3	(159.9)
1.2.1	Rate 6 - Sales	1 992.4	1 815.6	176.8
1.2.2	Rate 6 - T-Service	2 380.0	2 263.9	116.1
1.2	Total Rate 6	4 372.4	4 079.5	292.9
1.3.1	Rate 9 - Sales	1.5	1.8	(0.3)
1.3.2	Rate 9 - T-Service	0.3	0.4	(0.1)
1.3	Total Rate 9	1.8	2.2	(0.4)
1.	Total General Service Sales & T-Service	8 938.6	8 806.0	132.6
Contract Sales				
2.1	Rate 100	12.9	98.8	(85.9)
2.2	Rate 110	45.6	62.3	(16.7)
2.3	Rate 115	4.3	8.4	(4.1)
2.4	Rate 135	5.8	5.1	0.7
2.5	Rate 145	25.2	22.4	2.8
2.6	Rate 170	78.5	70.9	7.6
2.7	Rate 200	156.8	183.3	(26.5)
2.	Total Contract Sales	329.1	451.2	(122.1)
Contract T-Service				
3.1	Rate 100	59.6	494.0	(434.4)
3.2	Rate 110	529.0	602.2	(73.2)
3.3	Rate 115	429.1	627.4	(198.3)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	52.1	52.3	(0.2)
3.6	Rate 145	197.7	220.6	(22.9)
3.7	Rate 170	480.8	618.3	(137.5)
3.8	Rate 300	41.0	35.5	5.5
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 789.3	2 650.3	(861.0)
4.	Total Contract Sales & T-Service	2 118.4	3 101.5	(983.1)
5.	Total	11 057.0	11 907.5	(850.5)

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2009 BRIDGE YEAR ESTIMATE AND 2008 ACTUAL
($10^6 m^3$)

Item No.		Col. 1 2009 Bridge Year Estimate	Col. 2 2008 Actual	Col. 3 2009 Estimate Over (Under) 2008 Actual (1-2)	Col. 4 2008* Adjustments	Col. 5 2009 Estimate Over (Under) 2008 Actual with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	2 972.4	2 985.6	(13.2)	(128.8)	115.6
1.1.2	Rate 1 - T-Service	1 592.0	1 738.7	(146.7)	(73.0)	(73.7)
1.1	Total Rate 1	4 564.4	4 724.3	(159.9)	(201.8)	41.9
1.2.1	Rate 6 - Sales	1 992.4	1 815.6	176.8	(87.6)	264.4
1.2.2	Rate 6 - T-Service	2 380.0	2 263.9	116.1	(106.8)	222.9
1.2	Total Rate 6	4 372.4	4 079.5	292.9	(194.4)	487.3
1.3.1	Rate 9 - Sales	1.5	1.8	(0.3)	0.0	(0.3)
1.3.2	Rate 9 - T-Service	0.3	0.4	(0.1)	0.0	(0.1)
1.3	Total Rate 9	1.8	2.2	(0.4)	0.0	(0.4)
1.	Total General Service Sales & T-Service	8 938.6	8 806.0	132.6	(396.2)	528.8
Contract Sales						
2.1	Rate 100	12.9	98.8	(85.9)	(2.1)	(83.8)
2.2	Rate 110	45.6	62.3	(16.7)	(0.1)	(16.6)
2.3	Rate 115	4.3	8.4	(4.1)	0.0 **	(4.1)
2.4	Rate 135	5.8	5.1	0.7	0.0	0.7
2.5	Rate 145	25.2	22.4	2.8	(0.1)	2.9
2.6	Rate 170	78.5	70.9	7.6	0.0 **	7.6
2.7	Rate 200	156.8	183.3	(26.5)	(0.3)	(26.2)
2.	Total Contract Sales	329.1	451.2	(122.1)	(2.6)	(119.5)
Contract T-Service						
3.1	Rate 100	59.6	494.0	(434.4)	(6.6)	(427.8)
3.2	Rate 110	529.0	602.2	(73.2)	(1.6)	(71.6)
3.3	Rate 115	429.1	627.4	(198.3)	(0.1)	(198.2)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	52.1	52.3	(0.2)	0.0	(0.2)
3.6	Rate 145	197.7	220.6	(22.9)	(3.2)	(19.7)
3.7	Rate 170	480.8	618.3	(137.5)	(5.5)	(132.0)
3.8	Rate 300	41.0	35.5	5.5	0.0	5.5
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 789.3	2 650.3	(861.0)	(17.0)	(844.0)
4.	Total Contract Sales & T-Service	2 118.4	3 101.5	(983.1)	(19.6)	(963.5)
5.	Total	11 057.0	11 907.5	(850.5)	(415.8)	(434.7)

* Note: Weather normalization adjustments have been made to the 2008 Actuals utilizing the 2009 Board Approved Budget degree days in order to place the two years on a comparable basis.

** Less than 50,000 m^3.

The principal reasons for the variances contributing to the weather normalized decrease of 434.7 10^6m^3 in the 2009 Bridge Year Estimate over the 2008 Actual are as follows:

1. The volumetric increase of 41.9 10^6m^3 in Rate 1 is due to customer growth of 89.9 10^6m^3; partially offset by a lower average use per customer totalling 48.0 10^6m^3;

2. The volumetric increase of 487.3 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 534.2 10^6m^3 and customer growth of 10.8 10^6m^3; partially offset by a lower average use per customer totalling 14.4 10^6m^3 and a loss in load of 43.3 10^6m^3 relating to plant closures or relocations of Rate 6 Large Volume customers;

3. The volumetric decrease of 0.4 10^6m^3 in Rate 9 is due to a lower average use per station totalling 0.3 10^6m^3 and the loss of two stations of 0.1 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 963.5 10^6m^3 is due to decreases in the apartment sector of 180.6 10^6m^3, the commercial sector of 153.8 10^6m^3, the industrial sector of 602.9 10^6m^3 and Rate 200 of 26.2 10^6m^3. This decrease is primarily attributable to net customer migration to General Service of 534.2 10^6m^3 as stated above, one large distributed energy customer with distribution volume of 96.7 10^6m^3 migrating from Rate 115 to Rate 125 that has no distribution volume effective July 1, 2008, and plant closures resulting in a loss in load of 61.8 10^6m^3.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2009 BRIDGE YEAR ESTIMATE AND 2009 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2009 Bridge Year Estimate	Col. 2 2009 Board Approved Budget	Col. 3 2009 Estimate Over (Under) 2009 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	2 972.4	2 896.6	75.8
1.1.2	Rate 1 - T-Service	1 592.0	1 705.0	(113.0)
1.1	Total Rate 1	4 564.4	4 601.6	(37.2)
1.2.1	Rate 6 - Sales	1 992.4	1 819.2	173.2
1.2.2	Rate 6 - T-Service	2 380.0	2 659.8	(279.8)
1.2	Total Rate 6	4 372.4	4 479.0	(106.6)
1.3.1	Rate 9 - Sales	1.5	2.1	(0.6)
1.3.2	Rate 9 - T-Service	0.3	0.5	(0.2)
1.3	Total Rate 9	1.8	2.6	(0.8)
1.	Total General Service Sales & T-Service	8 938.6	9 083.2	(144.6)
Contract Sales				
2.1	Rate 100	12.9	0.0	12.9
2.2	Rate 110	45.6	71.5	(25.9)
2.3	Rate 115	4.3	4.4	(0.1)
2.4	Rate 135	5.8	3.3	2.5
2.5	Rate 145	25.2	22.5	2.7
2.6	Rate 170	78.5	56.3	22.2
2.7	Rate 200	156.8	151.3	5.5
2.	Total Contract Sales	329.1	309.3	19.8
Contract T-Service				
3.1	Rate 100	59.6	0.0	59.6
3.2	Rate 110	529.0	619.5	(90.5)
3.3	Rate 115	429.1	532.1	(103.0)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	52.1	54.8	(2.7)
3.6	Rate 145	197.7	203.6	(5.9)
3.7	Rate 170	480.8	545.6	(64.8)
3.8	Rate 300	41.0	51.7	(10.7)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 789.3	2 007.3	(218.0)
4.	Total Contract Sales & T-Service	2 118.4	2 316.6	(198.2)
5.	Total	11 057.0	11 399.8	(342.8)

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND TRANSPORTATION VOLUME BY RATE CLASS 2009 BRIDGE YEAR ESTIMATE AND 2009 BOARD APPROVED BUDGET

($10^6 m^3$)

Item No.		Col. 1 2009 Bridge Year Estimate	Col. 2 2009 Board Approved Budget	Col. 3 2009 Estimate Over (Under) 2009 Budget (1-2)	Col. 4 2009* Adjustments	Col. 5 2009 Estimate Over (Under) 2009 Budget with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	2 972.4	2 896.6	75.8	0.0	75.8
1.1.2	Rate 1 - T-Service	1 592.0	1 705.0	(113.0)	0.0	(113.0)
1.1	Total Rate 1	4 564.4	4 601.6	(37.2)	0.0	(37.2)
1.2.1	Rate 6 - Sales	1 992.4	1 819.2	173.2	0.0	173.2
1.2.2	Rate 6 - T-Service	2 380.0	2 659.8	(279.8)	0.0	(279.8)
1.2	Total Rate 6	4 372.4	4 479.0	(106.6)	0.0	(106.6)
1.3.1	Rate 9 - Sales	1.5	2.1	(0.6)	0.0	(0.6)
1.3.2	Rate 9 - T-Service	0.3	0.5	(0.2)	0.0	(0.2)
1.3	Total Rate 9	1.8	2.6	(0.8)	0.0	(0.8)
1.	Total General Service Sales & T-Service	8 938.6	9 083.2	(144.6)	0.0	(144.6)
Contract Sales						
2.1	Rate 100	12.9	0.0	12.9	0.0	12.9
2.2	Rate 110	45.6	71.5	(25.9)	0.0	(25.9)
2.3	Rate 115	4.3	4.4	(0.1)	0.0	(0.1)
2.4	Rate 135	5.8	3.3	2.5	0.0	2.5
2.5	Rate 145	25.2	22.5	2.7	0.0	2.7
2.6	Rate 170	78.5	56.3	22.2	0.0	22.2
2.7	Rate 200	156.8	151.3	5.5	0.0	5.5
2.	Total Contract Sales	329.1	309.3	19.8	0.0	19.8
Contract T-Service						
3.1	Rate 100	59.6	0.0	59.6	0.0	59.6
3.2	Rate 110	529.0	619.5	(90.5)	0.0	(90.5)
3.3	Rate 115	429.1	532.1	(103.0)	0.0	(103.0)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	52.1	54.8	(2.7)	0.0	(2.7)
3.6	Rate 145	197.7	203.6	(5.9)	0.0	(5.9)
3.7	Rate 170	480.8	545.6	(64.8)	0.0	(64.8)
3.8	Rate 300	41.0	51.7	(10.7)	0.0	(10.7)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 789.3	2 007.3	(218.0)	0.0	(218.0)
4.	Total Contract Sales & T-Service	2 118.4	2 316.6	(198.2)	0.0	(198.2)
5.	Total	11 057.0	11 399.8	(342.8)	0.0	(342.8)

*Note: As 2009 Bridge Year Estimate degree days are same as 2009 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 decrease of 342.8 10^6m^3 in the 2009 Bridge Year Estimate over the 2009 Board Approved Budget are as follows:

1. The volumetric decrease of 37.2 10^6m^3 in Rate 1 is due to a lower average use per customer totalling 27.5 10^6m^3 and an unfavourable customer variance of 9.7 10^6m^3;

2. The volumetric decrease of 106.6 10^6m^3 in Rate 6 is due to an unfavourable customer variance of 63.0 10^6m^3 and net customer migration to Contract Sales and T-Service of 84.5 10^6m^3; partially offset by a higher average use per customer totalling 40.9 10^6m^3;

3. The volumetric decrease of 0.8 10^6m^3 in Rate 9 is due to a lower average use per station totalling 0.7 10^6m^3 and the loss of one station of 0.1 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 198.2 10^6m^3 is due to decreases in the commercial sector of 17.0 10^6m^3 and the industrial sector of 227.4 10^6m^3; partially offset by an increase in the apartment sector of 40.7 10^6m^3 and Rate 200 of 5.5 10^6m^3.

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2008 ACTUAL

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	Col. 3 Revenues ($Millions)
General Service				
1.1.1	Rate 1 - Sales	1 078 118	2 985.6	1 475.7
1.1.2	Rate 1 - T-Service	630 402	1 738.7	343.7
1.1	Total Rate 1	1 708 520	4 724.3	1 819.4
1.2.1	Rate 6 - Sales	104 000	1 815.6	785.4
1.2.2	Rate 6 - T-Service	51 207	2 263.9	245.0
1.2	Total Rate 6	155 207	4 079.5	1 030.4
1.3.1	Rate 9 - Sales	26	1.8	0.8
1.3.2	Rate 9 - T-Service	3	0.4	0.1
1.3	Total Rate 9	29	2.2	0.9
1.	Total General Service Sales & T-Service	1 863 756	8 806.0	2 850.7
Contract Sales				
2.1	Rate 100	129	98.8	38.1
2.2	Rate 110	34	62.3	24.4
2.3	Rate 115	1	8.4	2.8
2.4	Rate 135	3	5.1	2.2
2.5	Rate 145	11	22.4	8.4
2.6	Rate 170	5	70.9	24.1
2.7	Rate 200	1	183.3	47.2
2.	Total Contract Sales	184	451.2	147.2
Contract T-Service				
3.1	Rate 100	580	494.0	46.2
3.2	Rate 110	209	602.2	42.1
3.3	Rate 115	48	627.4	36.2
3.4	Rate 125	3	0.0 *	4.2
3.5	Rate 135	37	52.3	3.4
3.6	Rate 145	164	220.6	15.8
3.7	Rate 170	29	618.3	27.7
3.8	Rate 300	10	35.5	0.5
3.9	Rate 315	0	0.0	0.2
3.	Total Contract T-Service	1 080	2 650.3	176.3
4.	Total Contract Sales & T-Service	1 264	3 101.5	323.5
5.	Total	1 865 020	11 907.5	3 174.2

* There is no distribution volume for Rate 125 customers.

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2008 ACTUAL AND 2007 ACTUAL

Item No.		Col. 1 2008 Actual	Col. 2 2007 Actual	Col. 3 2008 Actual Over (Under) 2007 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 078 118	1 019 738	58 380
1.1.2	Rate 1 - T-Service	630 402	650 448	(20 046)
1.1	Total Rate 1	1 708 520	1 670 186	38 334
1.2.1	Rate 6 - Sales	104 000	97 335	6 665
1.2.2	Rate 6 - T-Service	51 207	55 217	(4 010)
1.2	Total Rate 6	155 207	152 552	2 655
1.3.1	Rate 9 - Sales	26	26	0
1.3.2	Rate 9 - T-Service	3	4	(1)
1.3	Total Rate 9	29	30	(1)
1.	Total General Service Sales & T-Service	1 863 756	1 822 768	40 988
Contract Sales				
2.1	Rate 100	129	192	(63)
2.2	Rate 110	34	27	7
2.3	Rate 115	1	4	(3)
2.4	Rate 135	3	1	2
2.5	Rate 145	11	11	0
2.6	Rate 170	5	4	1
2.7	Rate 200	1	1	0
2.	Total Contract Sales	184	240	(56)
Contract T-Service				
3.1	Rate 100	580	1 266	(686)
3.2	Rate 110	209	235	(26)
3.3	Rate 115	48	57	(9)
3.4	Rate 125	3	1	2
3.5	Rate 135	37	37	0
3.6	Rate 145	164	148	16
3.7	Rate 170	29	28	1
3.8	Rate 300	10	9	1
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	1 080	1 781	(701)
4.	Total Contract Sales & T-Service	1 264	2 021	(757)
5.	Total	1 865 020	1 824 789	40 231

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2008 ACTUAL AND 2007 ACTUAL
(10^6m^3)

Item No.		Col. 1 2008 Actual	Col. 2 2007 Actual	Col. 3 2008 Actual Over (Under) 2007 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	2 985.6	2 872.9	112.7
1.1.2	Rate 1 - T-Service	1 738.7	1 818.2	(79.5)
1.1	Total Rate 1	4 724.3	4 691.1	33.2
1.2.1	Rate 6 - Sales	1 815.6	1 644.3	171.3
1.2.2	Rate 6 - T-Service	2 263.9	1 976.8	287.1
1.2	Total Rate 6	4 079.5	3 621.1	458.4
1.3.1	Rate 9 - Sales	1.8	2.0	(0.2)
1.3.2	Rate 9 - T-Service	0.4	0.6	(0.2)
1.3	Total Rate 9	2.2	2.6	(0.4)
1.	Total General Service Sales & T-Service	8 806.0	8 314.8	491.2
Contract Sales				
2.1	Rate 100	98.8	141.8	(43.0)
2.2	Rate 110	62.3	30.2	32.1
2.3	Rate 115	8.4	43.1	(34.7)
2.4	Rate 135	5.1	3.2	1.9
2.5	Rate 145	22.4	23.6	(1.2)
2.6	Rate 170	70.9	63.6	7.3
2.7	Rate 200	183.3	174.1	9.2
2.	Total Contract Sales	451.2	479.6	(28.4)
Contract T-Service				
3.1	Rate 100	494.0	899.4	(405.4)
3.2	Rate 110	602.2	577.8	24.4
3.3	Rate 115	627.4	851.6	(224.2)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	52.3	53.2	(0.9)
3.6	Rate 145	220.6	208.5	12.1
3.7	Rate 170	618.3	654.7	(36.4)
3.8	Rate 300	35.5	33.7	1.8
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	2 650.3	3 278.9	(628.6)
4.	Total Contract Sales & T-Service	3 101.5	3 758.5	(657.0)
5.	Total	11 907.5	12 073.3	(165.8)

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2008 ACTUAL AND 2007 ACTUAL
($10^6 m^3$)

Item No.		Col. 1 2008 Actual	Col. 2 2007 Actual	Col. 3 2008 Actual Over (Under) 2007 Actual (1-2)	Col. 4 2007* Adjustments		Col. 5 2008 Actual Over (Under) 2007 Actual with Adjustments (3-4)
General Service							
1.1.1	Rate 1 - Sales	2 985.6	2 872.9	112.7	22.6		90.1
1.1.2	Rate 1 - T-Service	1 738.7	1 818.2	(79.5)	11.3		(90.8)
1.1	Total Rate 1	4 724.3	4 691.1	33.2	33.9		(0.7)
1.2.1	Rate 6 - Sales	1 815.6	1 644.3	171.3	13.1		158.2
1.2.2	Rate 6 - T-Service	2 263.9	1 976.8	287.1	27.0		260.1
1.2	Total Rate 6	4 079.5	3 621.1	458.4	40.1		418.3
1.3.1	Rate 9 - Sales	1.8	2.0	(0.2)	0.0		(0.2)
1.3.2	Rate 9 - T-Service	0.4	0.6	(0.2)	0.0		(0.2)
1.3	Total Rate 9	2.2	2.6	(0.4)	0.0		(0.4)
1.	Total General Service Sales & T-Service	8 806.0	8 314.8	491.2	74.0		417.2
Contract Sales							
2.1	Rate 100	98.8	141.8	(43.0)	0.7		(43.7)
2.2	Rate 110	62.3	30.2	32.1	0.1		32.0
2.3	Rate 115	8.4	43.1	(34.7)	0.0	**	(34.7)
2.4	Rate 135	5.1	3.2	1.9	0.0		1.9
2.5	Rate 145	22.4	23.6	(1.2)	(0.1)		(1.1)
2.6	Rate 170	70.9	63.6	7.3	0.1		7.2
2.7	Rate 200	183.3	174.1	9.2	(0.5)		9.7
2.	Total Contract Sales	451.2	479.6	(28.4)	0.3		(28.7)
Contract T-Service							
3.1	Rate 100	494.0	899.4	(405.4)	2.0		(407.4)
3.2	Rate 110	602.2	577.8	24.4	0.9		23.5
3.3	Rate 115	627.4	851.6	(224.2)	0.0	**	(224.2)
3.4	Rate 125	0.0	0.0	0.0	0.0		0.0
3.5	Rate 135	52.3	53.2	(0.9)	0.0	**	(0.9)
3.6	Rate 145	220.6	208.5	12.1	(1.0)		13.1
3.7	Rate 170	618.3	654.7	(36.4)	(10.6)		(25.8)
3.8	Rate 300	35.5	33.7	1.8	0.0		1.8
3.9	Rate 315	0.0	0.0	0.0	0.0		0.0
3.	Total Contract T-Service	2 650.3	3 278.9	(628.6)	(8.7)		(619.9)
4.	Total Contract Sales & T-Service	3 101.5	3 758.5	(657.0)	(8.4)		(648.6)
5.	Total	11 907.5	12 073.3	(165.8)	65.6		(231.4)

* Note: Weather normalization adjustments have been made to the 2007 Actuals utilizing the 2008 Actual degree days in order to place the two years on a comparable basis.

** Less than 50,000 m³.

The principal reasons for the variances contributing to the weather normalized decrease of 231.4 10^6m^3 in the 2008 Actual over the 2007 Actual are as follows:

1. The volumetric decrease of 0.7 10^6m^3 in Rate 1 is due to a lower average use per customer totalling 105.8 10^6m^3; partially offset by customer growth of 105.1 10^6m^3;

2. The volumetric increase of 418.3 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 421.3 10^6m^3 and customer growth of 26.2 10^6m^3; partially offset by a lower average use per customer totalling 29.2 10^6m^3;

3. The volumetric decrease of 0.4 10^6m^3 in Rate 9 is due to a lower average use per station totalling 0.3 10^6m^3 and the loss of two stations of 0.1 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 648.6 10^6m^3 is due to decreases in the apartment sector of 220.8 10^6m^3, the commercial sector of 235.4 10^6m^3 and the industrial sector of 202.1 10^6m^3; partially offset by an increase in Rate 200 of 9.7 10^6m^3. This decrease is primarily attributable to net customer migration to General Service of 421.3 10^6m^3 as stated above, one large distributed energy customer with distribution volume of 95.9 10^6m^3 migrating from Rate 115 to Rate 125 that has no distribution volume effective July 1, 2008, and plant closures resulting in a loss in load of 50.1 10^6m^3.

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	Col. 14
		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 Bridge Year Estimate	2010 Budget
Residential		3,070	3,023	2,963	3,006	2,903	2,900	2,871	2,818	2,772	2,713	2,709	2,668	2,637	2,622
	Change		(47)	(60)	43	(103)	(3)	(29)	(53)	(46)	(59)	(4)	(41)	(31)	(15)
	% Change		-1.53%	-1.98%	1.45%	-3.43%	-0.10%	-1.00%	-1.85%	-1.63%	-2.13%	-0.15%	-1.51%	-1.16%	-0.57%
Apartment		77,746	80,682	80,260	80,097	80,513	82,092	82,822	82,849	81,913	86,624	101,511	125,079	145,689	149,051
	Change		2,936	(422)	(163)	416	1,579	730	27	(936)	4,711	14,887	23,568	20,610	3,362
	% Change		3.78%	-0.52%	-0.20%	0.52%	1.96%	0.89%	0.03%	-1.13%	5.75%	17.19%	23.22%	16.48%	2.31%
Commercial		16,904	16,814	17,045	17,464	17,269	17,472	17,251	17,107	17,030	16,870	17,351	18,132	18,928	18,596
	Change		(90)	231	419	(195)	203	(221)	(144)	(77)	(160)	481	781	796	(332)
	% Change		-0.53%	1.37%	2.46%	-1.12%	1.18%	-1.26%	-0.83%	-0.45%	-0.94%	2.85%	4.50%	4.39%	-1.75%
Industrial		51,476	54,085	55,322	58,283	56,280	53,229	55,825	51,301	53,956	54,251	59,673	74,909	97,797	101,484
	Change		2,609	1,237	2,961	(2,003)	(3,051)	2,596	(4,524)	2,655	295	5,422	15,236	22,888	3,687
	% Change		5.07%	2.29%	5.35%	-3.44%	-5.42%	4.88%	-8.10%	5.18%	0.55%	9.99%	25.53%	30.55%	3.77%

* All historical average uses are on a calendar-year basis and have been normalized to the 2010 Budget degree days.

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	Col. 14
		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009 Bridge Year Estimate	2010 Budget
Rate 1		3,070	3,023	2,963	3,006	2,903	2,900	2,871	2,818	2,772	2,713	2,709	2,668	2,637	2,622
	Change		(47)	(60)	43	(103)	(3)	(29)	(53)	(46)	(59)	(4)	(41)	(31)	(15)
	% Change		-1.53%	-1.98%	1.45%	-3.43%	-0.10%	-1.00%	-1.85%	-1.63%	-2.13%	-0.15%	-1.51%	-1.16%	-0.57%
Rate 6		21,119	21,250	21,435	21,853	21,555	21,653	21,587	21,256	21,215	21,264	22,632	25,156	27,901	27,949
	Change		131	185	418	(298)	98	(66)	(331)	(41)	49	1,368	2,524	2,745	48
	% Change		0.62%	0.87%	1.95%	-1.36%	0.45%	-0.30%	-1.53%	-0.19%	0.23%	6.43%	11.15%	10.91%	0.17%

* All historical average uses are on a calendar-year basis and have been normalized to the 2010 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	1995	Rate 1 & Rate 2	3,341	3,337	4	0.1%
		Rate 6	23,076	22,605	471	2.1%
		Total General Service	5,363	5,315	48	0.9%
	1996	Rate 1 & Rate 2	3,405	3,346	59	1.8%
		Rate 6	23,346	22,925	421	1.8%
		Total General Service	5,434	5,342	92	1.7%
	1997	Rate 1	3,320	3,269	51	1.6%
		Rate 6	23,127	22,504	623	2.8%
		Total General Service	5,296	5,190	106	2.0%
	1998	Rate 1	3,336	3,332	4	0.1%
		Rate 6	23,505	23,196	309	1.3%
		Total General Service	5,329	5,297	32	0.6%
	1999	Rate 1	3,246	3,329	(83)	-2.5%
		Rate 6	23,301	23,095	206	0.9%
		Total General Service	5,170	5,263	(93)	-1.8%
	2000	Rate 1	3,238	3,218	20	0.6%
		Rate 6	23,560	22,842	718	3.1%
		Total General Service	5,149	5,092	57	1.1%
	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	2,621	2,637	(16)	-0.6%
		Rate 6	27,735	28,165	(430)	-1.5%
		Total General Service	4,707	4,770	(63)	-1.3%
	2010	Rate 1		2,622		
		Rate 6		27,949		
		Total General Service		4,705		

* 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.

**2009 Bridge Year Estimate was reported at column 1 because actual numbers are not available

LARGE VOLUME (CONTRACT MARKET) CUSTOMER VOLUMES
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**	2,118.4	2,316.6	(198.2)	-8.6%
	2010		2,008.6		

* 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.

**2009 Bridge Year Estimate was reported at column 1 because actual numbers are not available

CUSTOMERS BUDGET

1. The purpose of this exhibit is to provide the details of the calculation of the 2010 annual average customers as indicated by active, unlocked meters and reported in the 2010 Revenue per Customer Cap formula at Exhibit B, Tab 1, Schedule 2. The annual average customer numbers calculation methodology used by the Company has been applied to calculate Board approved annual average customer numbers 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 some of the historical information shown in the Historical Actual vs. Board Approved section. The 2010 Test Year Budget includes calendar 2008 Actual and 2009 Bridge Year Estimate customer additions information.

2. The total customer additions for the 2010 Budget are 32,379. The forecast is described in detail in the evidence at Exhibit B, Tab 1, Schedule 4. These forecast customer additions correspond to an increase of 25,091 in the average number of customers (unlocked meters) between 2010 Budget and 2009 Board Approved Budget as shown in Exhibit B, Tab 1, Schedule 5, Appendix A, page 2. The 2009 Bridge Year Estimate customer additions that have incorporated four months actual are 33,268 which are lower than the 2009 Board Approved Budget of 41,241. This 2010 customer additions forecast underpins the new customer volumes of 87.4 10^6m^3 added between 2010 Budget and 2009 Estimate at Exhibit B, Tab 1, Schedule 5, page 5.

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 known as unlock

meters)[1] among the Company's customers that use gas. 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 (2009 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)

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

Witnesses: I. Chan
T. Ladanyi

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 (2009 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 meter or customer is defined as customer whose gas meter is locked and no gas is flowing through the meter to a premise. These can be vacant premises (e.g. new construction, move-in/move-out, bankruptcies), customers switching off gas to an alternate energy source, payment or credit reasons, and seasonal usage (e.g., cottage). As these factors can fluctuate, the historical average of the past three years' monthly actual data is used in order to obtain a forecast of lock meters for 2010 Budget. Table 1 below presents the past three years historical annual actual lock customer data.

Table 1 - Historical Annual Average of Lock Customers

Calendar Year	Lock Customers
2006	31,951
2007	33,240
2008	33,055

7. There is always a lag time between the date when the service line and meter are installed (the date that underpins capital expenditures and customer additions) and the date when the customer moves into the premise, calls to have the meter unlocked by field staff and gas service is activated for that customer's account (the date that underpins billed revenues and volumes). In order to obtain the accurate timing of actual billing and consumption profile this time lag is incorporated into the customer number calculation.

8. Similar to lock customers, this time lag varies and it can be difficult to predict a customer's behaviour, such as when the customer moves into the premise or when the premise is sold. Therefore, the latest available historical actual data is used in order to obtain an objective forecast of lock meters for the budget. Table 2 below presents a summary of the 2010 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 for residential homes.

Table 2 - 2010 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 next page, illustrates 14-Years of Historical Actual vs. Board Approved customer numbers. Overall, the average percentage error variances over the past 14 years were only 0.1% or 2,024 customers, which indicates that the existing methodology has continued to be a good predictor of actual customers.

11. The unfavourable customer numbers variance between 2009 Bridge Year Estimate and 2009 Board Approved Budget is primarily attributable to a decrease in customer additions between the Bridge Year Estimate of 33,269 and the Board Approved Budget of 41,241 as mentioned in paragraph 2 on page 1.

TABLE 3 - GENERAL SERVICE AND CONTRACT MARKET CUSTOMERS

		Col. 1	Col. 2	Col. 3	Col. 4
	Test Year	Actual Customers	Board Approved Customers	Variance Customers (1-2)	%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**	1,900,696	1,906,437	(5,741)	-0.3%
	2010		1,931,528		

* 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.

**2009 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.

BUDGET DEGREE DAYS

1. The purpose of this evidence is to provide the degree day forecasts for 2010[1].

2. The 2010 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 2010, the degree day forecasts are as follows:
   a. Central weather zone: 3,582 Environment Canada degree days; 3,546 Gas Supply degree days
   b. Eastern weather zone: 4,430 Environment Canada degree days; 4,390 Gas Supply degree days
   c. Niagara weather zone: 3,480 Environment Canada degree days; 3,433 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 2010. The model is estimated using data covering the period 1989 to 2008, 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 five year weighted average of Environment Canada degree days, a five year moving average of Environment Canada degree days and a trend[2]. The five year weighted averages and five year moving averages are lagged two years. Table 2 displays the actual Environment Canada degree day data for the Eastern weather zone, the five year weighted and moving averages and the trend data used to estimate the model. The resultant degree day forecast for 2010 is presented in Table 2 as well. The model is estimated over the period 1950 to 2008 a total of 59 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 1989 to 2008 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 1979 to 2008, a period of 30 years. Estimation results for the 20-Year Trend model are provided in Figure 3.

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[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 $(DD_{t-2}+DD_{t-3}+ \ldots +DD_{t-30}+DD_{t-31})/30$ 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]
1989	4,250	1	4,014
1990	3,631	2	3,993
1991	3,686	3	3,972
1992	4,112	4	3,952
1993	4,180	5	3,931
1994	4,115	6	3,911
1995	4,040	7	3,890
1996	4,177	8	3,870
1997	4,026	9	3,849
1998	3,220	10	3,828
1999	3,539	11	3,808
2000	3,826	12	3,787
2001	3,420	13	3,767
2002	3,630	14	3,746
2003	3,982	15	3,726
2004	3,798	16	3,705
2005	3,797	17	3,685
2006	3,378	18	3,664
2007	3,722	19	3,643
2008	3,837	20	3,623
2010 Forecast		22	3,582

[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	4,725
1951	4,587	2	4,622	4,594	4,704
1952	4,404	3	4,647	4,661	4,726
1953	4,059	4	4,657	4,641	4,707
1954	4,707	5	4,572	4,556	4,690
1955	4,689	6	4,467	4,385	4,633
1956	4,799	7	4,516	4,465	4,654
1957	4,405	8	4,489	4,523	4,691
1958	4,736	9	4,531	4,626	4,727
1959	4,718	10	4,532	4,584	4,700
1960	4,451	11	4,667	4,652	4,681
1961	4,586	12	4,669	4,669	4,685
1962	4,826	13	4,622	4,596	4,659
1963	4,921	14	4,579	4,584	4,665
1964	4,569	15	4,663	4,667	4,673
1965	4,810	16	4,701	4,753	4,702
1966	4,683	17	4,671	4,709	4,685
1967	4,882	18	4,743	4,755	4,679
1968	4,780	19	4,762	4,735	4,656
1969	4,698	20	4,773	4,775	4,669
1970	4,899	21	4,745	4,778	4,677
1971	4,797	22	4,771	4,762	4,655
1972	5,014	23	4,788	4,805	4,667
1973	4,420	24	4,811	4,808	4,656
1974	4,725	25	4,838	4,876	4,678
1975	4,514	26	4,766	4,736	4,626
1976	5,008	27	4,771	4,723	4,612
1977	4,597	28	4,694	4,637	4,591
1978	4,939	29	4,736	4,741	4,628
1979	4,589	30	4,652	4,695	4,631
1980	4,920	31	4,756	4,790	4,638
1981	4,438	32	4,729	4,735	4,614
1982	4,647	33	4,810	4,798	4,614
1983	4,536	34	4,697	4,674	4,586
1984	4,535	35	4,707	4,658	4,569
1985	4,659	36	4,626	4,601	4,565
1986	4,501	37	4,615	4,570	4,548
1987	4,328	38	4,563	4,585	4,572
1988	4,640	39	4,576	4,564	4,552
1989	4,931	40	4,512	4,482	4,527
1990	4,250	41	4,532	4,524	4,538
1991	4,303	42	4,612	4,657	4,576
1992	4,861	43	4,530	4,537	4,538
1993	4,780	44	4,490	4,461	4,508
1994	4,730	45	4,597	4,585	4,530
1995	4,585	46	4,625	4,646	4,548
1996	4,603	47	4,585	4,681	4,578
1997	4,786	48	4,652	4,680	4,548
1998	3,828	49	4,712	4,664	4,512
1999	4,137	50	4,697	4,689	4,527
2000	4,543	51	4,506	4,399	4,439
2001	4,115	52	4,387	4,276	4,414
2002	4,381	53	4,379	4,328	4,441
2003	4,715	54	4,282	4,240	4,426
2004	4,637	55	4,201	4,273	4,472
2005	4,421	56	4,378	4,444	4,492
2006	4,037	57	4,478	4,531	4,496
2007	4,447	58	4,454	4,511	4,491
2008	4,488	59	4,438	4,373	4,418
2010 Forecast		61	4,406	4,388	4,430

[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]
1979	3,799		3,642		
1980	3,932		3,649		
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	1	3,697	3,664	3,680
1990	3,307	2	3,705	3,650	3,678
1991	3,343	3	3,711	3,636	3,674
1992	3,759	4	3,697	3,623	3,660
1993	3,878	5	3,687	3,609	3,648
1994	3,780	6	3,692	3,595	3,643
1995	3,703	7	3,693	3,581	3,637
1996	3,786	8	3,701	3,567	3,634
1997	3,669	9	3,693	3,554	3,623
1998	2,980	10	3,704	3,540	3,622
1999	3,338	11	3,699	3,526	3,613
2000	3,596	12	3,670	3,512	3,591
2001	3,239	13	3,665	3,498	3,582
2002	3,415	14	3,659	3,485	3,572
2003	3,799	15	3,645	3,471	3,558
2004	3,632	16	3,631	3,457	3,544
2005	3,653	17	3,642	3,443	3,543
2006	3,163	18	3,639	3,429	3,534
2007	3,296	19	3,644	3,416	3,530
2008	3,480	20	3,619	3,402	3,510
2009 Forecast		22	3,586	3,374	3,480

[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: 1989 2008 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	4,034.1630	126.97	31.77	0.00
TREND	-20.5669	10.60	-1.94	0.07

R-squared	0.17	F-statistic	3.77
Adjusted R-squared	0.13	F-prob	0.07

Figure 2
Energy Probe Forecasting Equation and Test Statistics - Eastern

Sample: 1950 2008 Included observations: 59

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	3,994.7760	1,232.73	3.24	0.00
ECEDD5WA	0.5446	0.72	0.75	0.46
ECEDD5MA	-0.3861	0.77	-0.50	0.62
TREND	-4.1510	2.06	-2.02	0.05

R-squared	0.12	F-statistic	2.48
Adjusted R-squared	0.07	F-prob	0.07

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

Sample: 1989 2008 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	3,677.6630	116.88	31.46	0.00
TREND	-13.7898	9.76	-1.41	0.17

R-squared	0.10	F-statistic	2.00
Adjusted R-squared	0.05	F-prob	0.17

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 2010 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]**
1989	4,250	4,190	4,175
1990	3,631	3,574	3,592
1991	3,686	3,649	3,644
1992	4,112	3,989	4,045
1993	4,180	4,040	4,109
1994	4,115	4,084	4,048
1995	4,040	3,991	3,977
1996	4,177	4,133	4,106
1997	4,026	3,966	3,964
1998	3,220	3,202	3,206
1999	3,539	3,497	3,506
2000	3,826	3,784	3,776
2001	3,420	3,400	3,395
2002	3,630	3,597	3,592
2003	3,982	3,949	3,922
2004	3,798	3,766	3,750
2005	3,797	3,750	3,749
2006	3,378	3,355	3,355
2007	3,722	3,659	3,678
2008	3,837	3,801	3,786
2010 Forecast	3,582		3,546

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

Gas Supply degree days = 177.7054+0.9405(Environment Canada degree days)

Witness: J. Denomy

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	4,380
1974	4,725	4,858	4,673
1975	4,514	4,229	4,470
1976	5,008	4,901	4,944
1977	4,597	4,604	4,550
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	4,398
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	4,292
1988	4,640	4,601	4,591
1989	4,931	4,883	4,870
1990	4,250	4,225	4,218
1991	4,303	4,270	4,269
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	3,813
1999	4,137	4,112	4,109
2000	4,543	4,506	4,499
2001	4,115	4,071	4,088
2002	4,381	4,317	4,343
2003	4,715	4,663	4,663
2004	4,637	4,598	4,589
2005	4,421	4,397	4,381
2006	4,037	4,012	4,014
2007	4,447	4,411	4,406
2008	4,488	4,431	4,446
2010 Forecast	4,430		4,390

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

Gas Supply degree days = 146.0330+0.9580(Environment Canada degree days)

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]
1984	3,716	3,739	3,625
1985	3,651	3,649	3,572
1986	3,603	3,384	3,533
1987	3,441	3,600	3,401
1988	3,693	3,611	3,606
1989	3,845	3,599	3,730
1990	3,307	3,511	3,292
1991	3,343	3,287	3,321
1992	3,759	3,636	3,660
1993	3,878	3,667	3,757
1994	3,780	3,616	3,677
1995	3,703	3,577	3,614
1996	3,786	3,808	3,682
1997	3,669	3,646	3,586
1998	2,980	2,931	3,025
1999	3,338	3,277	3,317
2000	3,596	3,553	3,527
2001	3,239	3,162	3,236
2002	3,415	3,304	3,379
2003	3,799	3,688	3,693
2004	3,632	3,485	3,556
2005	3,653	3,580	3,573
2006	3,163	3,079	3,174
2007	3,296	3,349	3,282
2008	3,480	3,510	3,433
2010 Forecast	3,480		3,433

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

Gas Supply degree days = 596.4261+0.8150(Environment Canada degree days)

Witness: J. Denomy

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 2010[2] revenue class 20 is forecast to comprise 87% of Rate 1 volumes while revenue classes 12, 48 and 73 are forecast to collectively comprise 97% of Rate 6 volumes. Volumes for the remaining revenue classes in Rate 1 are forecast to comprise 13% of Rate 1 volumes while the remaining revenue classes in Rate 6 are forecast to comprise 3% of Rate 6 volumes.

3. For the 2001 budget the Company moved to a more objective forecasting methodology in order to remove any 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 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

[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.

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 B, Tab 1, Schedule 5 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 continue to produce accurate forecasts of general service average use.

Error Correction Model

6. The Error Correction Model ("ECM") 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 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

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

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 standard dynamic single-equation model and the ECM approach 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 2010.

Average Use Forecasting Methodology

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 uncertainty: (1) model specification, (2) forecast error from the driver variables used

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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.

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 2008. Out-of-sample, or ex-ante, means that the model incorporates only a portion of the sample, in this case 1985 to 2006. Forecasts of average use are produced under both approaches and measured against actual average use from 2007 to 2008 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 typically two years. Table 1 presents the forecast accuracy statistics for Rate 1 and Rate 6. The smaller the MPE and RMSPE the better, on average, the model's forecast performance.

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)	0.90%	-1.41%
In-Sample RMSPE (2 Years)	0.90%	1.42%
Out-of-Sample % Variance (2 Years)	2.94%	-8.52%
Out-of-Sample RMSPE (2 Years)	3.27%	9.22%

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

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

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.

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%

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

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

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

[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: 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	Dummy Variable for Recession Impact
CENTEMP	Central Weather Zone Employment
ECM_Region	Error Correction Term for Each Region

Witness: J. Denomy

TABLE 5 - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Metro Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.59	7.13	0.00
LOG(CDD)	0.70	15.48	0.00
LOG(REALCRCRPG)	-0.04	-2.34	0.03
LOG(MET20VINT)	0.57	9.76	0.00
DUM2008	-0.04	-2.28	0.03
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.02		
F-statistic	241.84		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.33	0.74
DLOG(CDD)	0.75	24.16	0.00
DLOG(MET20VINT)	0.86	2.10	0.05
DUM2008	-0.02	-1.55	0.14
ECM_MET20(-1)	-0.50	-2.06	0.05
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	175.79		0.00

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.23	1.81	0.09
LOG(CDD)	0.70	24.05	0.00
LOG(REALCRCRPG)	-0.11	-8.06	0.00
LOG(WES20VINT)	0.23	6.03	0.00
LOG(CENTEMP)	0.14	1.96	0.07
DUM2008	-0.03	-3.08	0.01
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	473.46		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.35	0.73
DLOG(CDD)	0.72	37.32	0.00
DLOG(REALCRCRPG)	-0.07	-3.87	0.00
DLOG(WES20VINT)	0.20	1.79	0.09
DUM2008	-0.03	-3.44	0.00
ECM_WES20(-1)	-0.77	-3.34	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	314.20		0.00

Central Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.12	0.15	0.88
LOG(CDD)	0.71	18.47	0.00
LOG(REALCRCRPG)	-0.09	-4.68	0.00
LOG(CEN20VINT)	0.33	9.33	0.00
LOG(CENTEMP)	0.27	3.35	0.00
DUM2008	-0.04	-3.16	0.01
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	319.97		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.71	0.49
DLOG(CDD)	0.71	23.78	0.00
DLOG(REALCRCRPG)	-0.04	-1.42	0.17
DLOG(CEN20VINT)	0.31	2.36	0.03
DUM2008	-0.05	-3.48	0.00
ECM_CEN20(-1)	-1.21	-4.69	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	133.89		0.00

Witness: J. Denomy

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	0.48	0.62	0.54
LOG(CDD)	0.71	20.85	0.00
LOG(REALCRCRPG)	-0.11	-6.97	0.00
LOG(NOR20VINT)	0.27	8.88	0.00
LOG(CENTEMP)	0.24	2.83	0.01
DUM2008	-0.03	-2.49	0.02
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	506.16		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.41	0.68
DLOG(CDD)	0.71	28.64	0.00
DLOG(REALCRCRPG)	-0.09	-3.90	0.00
DLOG(NOR20VINT)	0.21	2.18	0.04
DUM2008	-0.04	-3.02	0.01
ECM_NOR20(-1)	-1.24	-5.17	0.00
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	181.18		0.00

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.60	4.61	0.00
LOG(EDD)	0.78	18.39	0.00
LOG(REALERCRPG)	-0.06	-4.03	0.00
LOG(ERC20VINT)	0.23	16.36	0.00
DUM2008	-0.04	-2.71	0.01
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	401.21		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.84	0.01
DLOG(EDD)	0.77	22.76	0.00
DLOG(REALERCRPG)	-0.04	-1.51	0.15
DUM2008	-0.04	-2.44	0.03
ECM_ERC20(-1)	-1.00	-3.43	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	144.09		0.00

Niagara Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.30	5.68	0.00
LOG(NDD)	0.71	14.03	0.00
LOG(TIME)	-0.04	-2.78	0.01
LOG(REALNRCRPG)	-0.13	-3.72	0.00
LOG(NRC20VINT)	0.32	1.77	0.09
DUM2008	-0.05	-2.36	0.03
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.02		
F-statistic	190.68		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-3.05	0.01
DLOG(NDD)	0.71	22.21	0.00
DLOG(REALNRCRPG)	-0.06	-2.19	0.04
DUM2008	-0.03	-2.13	0.05
ECM_NRC20(-1)	-0.63	-2.89	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	141.40		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	0.21	0.01	0.24	0.19	0.13	0.84
	P Value	0.65	0.93	0.62	0.66	0.72	0.36
ARCH Test	Test Statistic	0.26	0.04	0.86	0.84	0.32	0.63
	P Value	0.61	0.84	0.35	0.36	0.57	0.43
Chow Forecast Test: Forecast from 2007 to 2008	Test Statistic	2.81*	4.61*	3.62*	2.85*	2.73*	1.68*
	P Value	0.09	0.03	0.05	0.09	0.09	0.22
Ramsey RESET Test	Test Statistic	1.56	0.54	0.04	0.13	0.03	0.44
	P Value	0.23	0.47	0.84	0.73	0.87	0.51

*without dum2008

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
CRCINDVAC	GTA Industrial Vacancy Rate
TIME	Time Trend
DUMPRE1991	Dummy Variable for Structural Break Prior to 1991
DUMRegion	Dummy Variable for Migration Impact
DUMXXXX	Dummy Variable for the Break in the Year XXXX
AR(1)	First-order Autoregressive Process Term
ECM_Region	Error Correction Term for Each Region

Witness: J. Denomy

TABLE 8 - RATE 6 REVENUE CLASS 12 REGRESSION EQUATIONS

Central Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	0.59	0.34	0.74
LOG(CDD)	0.60	5.76	0.00
LOG(REALCRCCPG)	-0.09	-1.35	0.20
LOG(CENTEMP)	0.76	4.60	0.00
DUM1996	-0.10	-4.38	0.00
DUMCRC12	0.23	5.10	0.00
AR(1)	0.37	1.41	0.18
R-squared	0.94		
Adjusted R-squared	0.91		
S.E. of regression	0.03		
F-statistic	38.418		0.00

Eastern Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	6.64	12.79	0.00
LOG(EDD)	0.53	8.27	0.00
LOG(TIME)	-0.02	-4.45	0.00
LOG(REALERCCPG)	-0.03	-1.81	0.09
DUMERC12	0.25	11.99	0.00
R-squared	0.93		
Adjusted R-squared	0.91		
S.E. of regression	0.02		
F-statistic	60.68		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.63	0.53
DLOG(EDD)	0.56	11.56	0.00
DLOG(REALERCCPG)	-0.05	-1.47	0.16
DUMERC12	0.25	11.67	0.00
ECM_ERC12(-1)	-0.95	-3.40	0.00
R-squared	0.95		
Adjusted R-squared	0.94		
S.E. of regression	0.02		
F-statistic	80.88		0.00

Niagara Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	4.91	5.89	0.00
LOG(NDD)	0.56	10.65	0.00
LOG(TIME)	-0.02	-3.16	0.01
LOG(REALNRCCPG)	-0.03	-1.25	0.23
LOG(NIAGEMP)	0.25	2.26	0.04
DUMNRC12	-0.03	-2.15	0.05
R-squared	0.89		
Adjusted R-squared	0.87		
S.E. of regression	0.02		
F-statistic	30.60		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.81	0.43
DLOG(NDD)	0.49	14.02	0.00
DLOG(NIAGEMP)	0.23	2.42	0.03
DLOG(REALNRCCPG)	-0.03	-0.94	0.36
DUMNRC12	-0.01	-0.77	0.45
ECM_NRC12(-1)	-0.98	-3.95	0.00
R-squared	0.93		
Adjusted R-squared	0.91		
S.E. of regression	0.02		
F-statistic	48.15		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	0.03	0.04	0.97
LOG(CDD)	0.89	15.64	0.00
LOG(TIME)	-0.12	-9.16	0.00
LOG(CRCCOMVAC)	-0.07	-4.78	0.00
LOG(ONTGDP)	0.25	4.26	0.00
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	181.61		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.44	0.67
DLOG(CDD)	0.87	30.13	0.00
DLOG(TIME)	-0.07	-3.76	0.00
DLOG(CRCCOMVAC)	-0.06	-4.15	0.00
DLOG(ONTGDP)	0.12	0.99	0.34
ECM_CRC48(-1)	-0.91	-5.50	0.00
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	192.13		0.00

Eastern Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.63	1.95	0.07
LOG(EDD)	0.74	11.57	0.00
LOG(TIME)	-0.16	-16.24	0.00
LOG(ONTGDP)	0.20	4.72	0.00
DUMERC48	0.06	3.00	0.01
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	224.62		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.04	0.97
DLOG(EDD)	0.79	21.45	0.00
DLOG(TIME)	-0.11	-5.05	0.00
DUMERC48	0.06	3.97	0.00
ECM_ERC48(-1)	-1.13	-6.18	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	128.32		0.00

Niagara Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.79	-0.51	0.62
LOG(NDD)	0.70	11.62	0.00
LOG(TIME)	-0.09	-4.64	0.00
LOG(REALNRCCPG)	-0.17	-4.24	0.00
LOG(ONTGDP)	0.39	3.60	0.00
R-squared	0.92		
Adjusted R-squared	0.91		
S.E. of regression	0.02		
F-statistic	56.28		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-1.22	0.24
DLOG(NDD)	0.69	22.75	0.00
DLOG(REALNRCCPG)	-0.11	-3.82	0.00
DLOG(ONTGDP)	0.38	2.34	0.03
ECM_NRC48(-1)	-1.18	-4.75	0.00
AR(1)	0.52	1.87	0.08
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	98.44		0.00

Witness: J. Denomy

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	4.61	1.85	0.08
LOG(CDD)	0.49	3.57	0.00
LOG(TIME)	-0.11	-3.21	0.00
LOG(CRCINDVAC)	-0.04	-1.12	0.28
LOG(ONTGDP)	0.22	1.28	0.22
DUMCRC73	0.18	4.52	0.00
R-squared	0.82		
Adjusted R-squared	0.78		
S.E. of regression	0.04		
F-statistic	16.897		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.53	0.60
DLOG(CDD)	0.53	10.03	0.00
DLOG(TIME)	-0.07	-2.21	0.04
DLOG(ONTGDP)	0.29	1.47	0.16
DUMCRC73	0.09	4.54	0.00
ECM_CRC73(-1)	-0.90	-5.41	0.00
R-squared	0.93		
Adjusted R-squared	0.92		
S.E. of regression	0.02		
F-statistic	48.47		0.00

Eastern Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-227,466.20	-2.91	0.01
EDD	13.73	1.18	0.25
TIME	-6,305.70	-7.66	0.00
EASTEMP	649.66	5.57	0.00
DUM2003	72,119.63	5.45	0.00
DUM2004	-93,990.38	-7.69	0.00
DUMERC73	20,526.54	1.82	0.09
R-squared	0.93		
Adjusted R-squared	0.90		
S.E. of regression	10,896.65		
F-statistic	35.13		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-7,062.89	-2.68	0.02
D(EDD)	12.88	1.70	0.11
D(EASTEMP)	899.40	4.50	0.00
DUM2003	64,176.46	5.76	0.00
DUM2004	-164,467.90	-16.05	0.00
DUM2005	87,899.49	8.99	0.00
ECM_ERC73(-1)	-1.29	-5.05	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	9,507.78		
F-statistic	97.74		0.00

Niagara Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-5.02	-1.05	0.31
LOG(NDD)	0.50	1.54	0.14
LOG(TIME)	-0.16	-2.76	0.01
LOG(REALNRCCPG)	-0.18	-1.35	0.19
LOG(MANUFACTURING)	1.10	3.45	0.00
DUM2002	-0.37	-3.10	0.01
DUMNRC73	0.56	5.57	0.00
R-squared	0.77		
Adjusted R-squared	0.69		
S.E. of regression	0.11		
F-statistic	9.37		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.02	-0.72	0.48
DLOG(NDD)	0.55	2.66	0.02
DLOG(MANUFACTURING)	0.65	1.59	0.13
DUM2002	-0.34	-3.45	0.00
DUM2003	0.33	3.42	0.00
DUMNRC73	0.31	3.89	0.00
ECM_NRC73(-1)	-0.72	-2.65	0.02
R-squared	0.87		
Adjusted R-squared	0.82		
S.E. of regression	0.09		
F-statistic	17.27		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	0.10	0.03	2.56	1.57	1.88	0.01	0.40	2.03	0.15
	P Value	0.75	0.87	0.11	0.21	0.17	0.93	0.53	0.15	0.69
ARCH Test	Test Statistic	0.13	0.35	0.04	0.71	0.79	0.27	0.72	2.49	0.01
	P Value	0.72	0.55	0.83	0.40	0.37	0.60	0.40	0.11	0.92
Chow Forecast Test: Forecast from 2007 to 2008	Test Statistic	63.95*	79.5**	0.83***	2.31	6.24****	1.00	10.37*****	0.65	9.63*****
	P Value	0.00	0.00	0.45	0.13	0.01	0.39	0.00	0.54	0.00
Ramsey RESET Test	Test Statistic	0.24	2.51	3.04	0.31	1.32	0.47	1.12	2.69	0.08
	P Value	0.63	0.13	0.10	0.58	0.27	0.50	0.31	0.12	0.78

*without dumcrc12
**without dumerc12
***without dumnrc12
**** without dumerc48
***** without dumcrc73
******without dumnrc73

14. Driver variable assumptions are presented in Table 10 in year over year growth rates. Major driver variables in the model are balance point heating degree days adjusted for billing cycles, vintage, time trend, real energy prices and economic variables. The driver variable assumptions are based on economic assumptions from the Economic Outlook, Spring 2009.

15. Higher natural gas prices have a negative impact on average use. Sharp increases will have two effects. First, it will cause customers to change their fuel use habits, for example, by lowering thermostat settings. Second, price increases will likely cause customers to purchase more efficient furnaces and other appliances. In addition, homeowners could retrofit older residences in order to reduce their energy consumption. Real energy prices are used in the model. The Consumer Price Index ("CPI") is used to convert nominal gas prices to real gas prices. Nominal energy price forecasts are based on the PIRA Henry Hub price forecast produced in May 2009.

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:

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

20. Fiscal 1991 is used as the reference year for the vintage ratio since the Energy Efficiency Act prohibited selling of conventional low-efficiency furnaces 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

[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.

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.

TABLE-10
Economic Outlook

CANADA & U.S.

CALENDAR YEAR	**2004**	**2005**	**2006**	**2007**	**2008**	**2009F**	**2010F**
REAL GDP (% CHANGE)							
CANADA	3.1	2.9	3.1	2.7	0.5	-2.1	2.0
U.S.	3.6	2.9	2.8	2.0	1.1	-2.4	2.0
REAL EXPORTS (% CHANGE)	5.0	1.8	0.6	1.0	-4.7	-10.1	1.5
REAL IMPORTS (% CHANGE)	8.0	7.1	4.6	5.5	0.8	-10.4	1.7
HOUSING STARTS (000's)	233	225	227	228	211	143	154
UNEMPLOYMENT RATE (%)	7.2	6.8	6.3	6.0	6.1	8.4	8.8
EMPLOYMENT GROWTH (% CHANGE)	1.8	1.4	1.9	2.3	1.5	-2.0	0.2
CONSUMER PRICES (% CHANGE)							
CANADA	1.9	2.2	2.0	2.1	2.4	0.1	1.6
U.S.	2.7	3.4	3.2	2.9	3.8	-0.5	1.3

TABLE-10 CONTINUED
Economic Outlook

ONTARIO

CALENDAR YEAR	2004	2005	2006	2007	2008	2009F	2010F
REAL GDP (% CHANGE)	2.6	2.8	2.6	2.3	-0.4	-1.8	2.1
REAL MANUFACTURING OUTPUT (% CHANGE)	-0.3	0.9	-2.1	-2.1	-8.6	-7.2	4.6
HOUSING STARTS (000's)	85.1	78.8	73.4	68.1	75.1	55.1	56.8
UNEMPLOYMENT RATE (%)	6.7	6.6	6.3	6.4	6.5	9.0	9.4
EMPLOYMENT GROWTH (% CHANGE)	1.7	1.4	1.5	1.5	1.4	-2.0	0.4
CONSUMER PRICES (% CHANGE)	1.9	2.2	1.8	1.8	2.3	0.3	1.8
RETAIL SALES (% CHANGE)	3.2	4.8	4.1	3.9	3.5	-3.4	2.8
WAGE RATE (% CHANGE)	5.2	5.0	4.5	4.7	2.4	0.9	4.5
REAL RESIDENTIAL NATURAL GAS PRICE (% CHANGE)	1.9	8.8	8.9	-11.4	1.5	-17.6	7.7
REAL COMMERCIAL NATURAL GAS PRICE (% CHANGE)	2.3	10.1	10.0	-12.7	1.6	-19.5	7.5

TABLE-10 CONTINUED
Economic Outlook

REGIONS

CALENDAR YEAR	2004	2005	2006	2007	2008	2009F	2010F
GTA							
HOUSING STARTS (000's)	44.7	43.0	38.8	35.7	42.4	31.2	30.3
SINGLES	21.5	17.7	15.9	16.1	11.9	8.2	11.0
MULTIPLES	23.2	25.4	22.9	19.7	30.4	23.0	19.4
CONSUMER PRICES (% CHANGE)	1.6	1.9	1.6	1.9	2.4	0.6	1.9
UNEMPLOYMENT RATE (%)	6.8	6.8	6.3	6.5	6.6	8.7	8.4
EMPLOYMENT GROWTH (% CHANGE)	2.3	1.8	1.8	2.0	1.8	-0.5	2.6
COMMERCIAL VACANCY RATE (%)	10.6	9.3	7.3	6.3	5.4	6.0	6.0
INDUSTRIAL VACANCY RATE (%)	5.0	4.9	5.1	5.4	5.9	6.7	6.7
VINTAGE METRO REGION CENTRAL WEATHER ZONE (% CHANGE)	-0.9	-1.1	-1.1	-1.8	-0.9	-0.9	-0.9
VINTAGE WESTERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-3.8	-3.3	-2.5	-2.7	-2.1	-2.0	-2.0
VINTAGE CENTRAL REGION CENTRAL WEATHER ZONE (% CHANGE)	-4.0	-3.6	-3.8	-3.1	-2.7	-2.6	-2.4
VINTAGE NORTHERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-4.2	-3.7	-3.8	-3.6	-3.1	-2.9	-2.7
EASTERN							
HOUSING STARTS (000's)	7.5	5.2	6.1	6.8	7.2	5.3	5.3
SINGLES	3.5	2.5	2.7	3.1	3.1	1.7	2.3
MULTIPLES	4.0	2.6	3.4	3.6	4.1	3.6	3.0
CONSUMER PRICES (% CHANGE)	1.9	2.3	1.7	1.9	2.2	0.7	2.0
UNEMPLOYMENT RATE (%)	6.6	6.7	5.4	5.7	4.9	5.9	6.0
EMPLOYMENT GROWTH (% CHANGE)	-0.7	1.7	3.2	1.2	3.4	-0.8	1.5
VINTAGE EASTERN WEATHER ZONE (% CHANGE)	-3.4	-3.0	-2.7	-2.8	-3.1	-3.0	-2.8
NIAGARA							
HOUSING STARTS (000's)	2.0	1.5	1.4	1.3	1.3	0.9	1.0
SINGLES	1.5	1.1	0.9	0.9	0.8	0.5	0.7
MULTIPLES	0.6	0.4	0.4	0.4	0.5	0.4	0.4
UNEMPLOYMENT RATE (%)	7.3	7.0	6.4	6.8	7.2	8.4	7.8
EMPLOYMENT GROWTH (% CHANGE)	-2.5	3.1	-1.2	1.4	2.6	-1.7	1.4
VINTAGE NIAGARA WEATHER ZONE (% CHANGE)	-1.4	-1.4	-1.2	-1.1	-1.1	-1.1	-1.1

TABLE-10 CONTINUED
Economic Outlook

INTEREST RATE & EXCHANGE RATE FORECAST

CALENDAR YEAR		2004	2005	2006	2007	2008	2009F	2010F
Canada								
Interest Rates	Overnight Rate	2.25	2.67	4.06	4.35	2.96	0.40	0.46
	Bank Rate	2.50	2.92	4.31	4.60	3.21	0.65	0.71
	Prime Rate	4.00	4.42	5.81	6.10	4.73	2.23	2.21
	1 Year Mortgage Rate	4.59	5.06	6.28	6.90	6.70	4.04	4.22
	3 Year Mortgage Rate	5.65	5.59	6.45	7.09	6.87	4.44	4.81
	5 Year Mortgage Rate	6.23	5.99	6.66	7.07	7.06	5.23	5.37
Money Markets	1 Month T-Bills	2.12	2.56	3.93	4.05	2.24	0.25	0.64
	3 Month T-Bills	2.22	2.73	4.04	4.12	2.30	0.31	0.77
	6 Month T-Bills	2.32	2.87	4.12	4.26	2.46	0.36	0.90
	1 Year T-Bills	2.55	3.09	4.19	4.32	2.56	0.45	1.08
	1 Month Bankers Acceptance	2.27	2.74	4.13	4.51	3.04	0.39	0.71
	3 Month Bankers Acceptance	2.31	2.84	4.19	4.57	3.08	1.05	1.44
	1 Month Commercial Paper	2.28	2.75	4.15	4.57	3.17	0.57	0.78
	3 Month Commercial Paper	2.31	2.84	4.21	4.63	3.23	0.61	0.90
Benchmark Government Bond Yields	2 Year	2.97	3.21	4.05	4.19	2.62	1.01	1.51
	3 Year	3.36	3.35	4.08	4.21	2.79	1.37	1.80
	5Year	3.82	3.59	4.12	4.22	3.01	1.91	2.22
	7 Year	4.22	3.81	4.16	4.24	3.26	2.23	2.51
	10Year	4.59	4.05	4.22	4.28	3.58	3.01	3.19
	30 Year	5.14	4.40	4.28	4.32	4.05	3.78	3.80
United States								
Interest Rates	Federal Funds Rate	1.40	3.25	5.02	5.00	1.86	0.13	0.24
	Prime Rate	4.34	6.19	7.96	8.05	5.09	3.06	3.50
	30 Year Mortgage Rate	5.84	5.87	6.41	6.34	6.04	4.93	5.12
Money Markets	1 Month T-Bills	1.27	3.00	4.75	4.40	1.29	0.10	0.45
	3 Month T-Bills	1.40	3.21	4.85	4.47	1.39	0.15	0.60
	6 Month T-Bills	1.61	3.50	4.99	4.61	1.66	0.31	0.78
	1 Month Non-Financial Commercial Paper	1.38	3.24	4.97	5.02	1.98	0.22	0.25
	3 Month Non-Financial Commercial Paper	1.49	3.40	5.03	4.99	2.12	0.33	0.32
	1 Month Financial Commercial Paper	1.40	3.27	5.00	5.07	2.38	0.34	0.34
	3 Month Financial Commercial Paper	1.52	3.44	5.06	5.13	2.64	0.51	0.40
Treasury Bond Yields	1 Year	1.89	3.62	4.93	4.52	1.82	0.61	1.09
	2 Year	2.38	3.85	4.82	4.36	2.00	0.92	1.31
	3 Year	2.78	3.93	4.77	4.34	2.24	1.30	1.66
	5 Year	3.43	4.05	4.75	4.43	2.80	1.86	2.20
	7 Year	3.87	4.15	4.76	4.50	3.17	2.45	2.75
	10 Year	4.27	4.29	4.79	4.63	3.67	2.97	3.21
	20 Year	5.05	4.65	4.99	4.91	4.36	3.92	4.07
	30 Year	5.00	4.60	4.87	4.83	4.28	3.80	3.99
Exchange Rate	$CDN/$US	1.30	1.21	1.13	1.07	1.07	1.22	1.21
	$US/$CDN	0.77	0.83	0.88	0.93	0.94	0.82	0.83

Risks to the Forecast

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 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 and 2006.

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 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.

Y FACTOR POWER GENERATION PROJECTS

1. Enbridge Gas Distribution has two power generation projects budgeted for 2010. Table 1 summarizes capital expenditure and other project details for the following:
   i. York Energy Centre, and
   ii. Greenfield South.

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. The project is currently in the pre-engineering phase. Pending Board approval, construction is currently forecast to begin May 2010 with gas delivery beginning in April 2011.

3. The Greenfield South power generation facility is proceeding under contract with the Ministry of Energy. To date, a gas delivery agreement has not been executed. The Company has budgeted for the Greenfield South facility pending commitment from Greenfield South to proceed.

4. Details of the above projects can be found in Table 1. The 2010 revenue requirement shown at Appendix A does not however include any impact from the Table 1 projects. Only those projects in service prior to the end of 2010 which were not included within 2007 base rates, namely the Portlands Energy Center put in service in 2008 and Thorold Cogen which was put in service in September 2009, are included within the Appendix A revenue requirement.

Witnesses: K. Culbert
T. Ladanyi

Table 1
Summary of 2010 Power Generation Related Projects

Facility	York Energy Centre Pipeline Project	Greenfield South Pipeline Project
Location	Township of King	Mississauga
Proposed Completion Date	April 2011	2011 [2]
Pipe Size and Length	NPS 16, 16.7 km	NPS 12, 650 m
2010 Budget	$33.7-M [1]	$1.18-M
Total Forecast Budget	$39.1-M [1]	$2.04-M

[1] This amount represents the total project budget for the York Energy Centre Pipeline Project. The capitalized assets are based on Forecast Budget net Customer Contribution (i.e. York Energy Centre Pipeline Project – Net 2010 Budget of $23.1-M and Net Total Forecast Budget of $26.8-M).

[2] Completion and in-service date of the Greenfield South facility pending commitment from Greenfield south to proceed with project.

Witnesses: K. Culbert
T. Ladanyi

CAPITAL STRUCTURE
POWER GENERATION Y-FACTOR CALCULATION

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

	($000's)	2008	2009	2010
7.	Ontario Utility Income	86.4	(253.7)	(399.7)
8.	Rate base	8,174.6	23,952.9	27,911.6
9.	Indicated rate of return	1.06 %	(1.06)%	(1.43)%
10.	(Def.) / suff. in rate of return	(6.52)%	(8.64)%	(9.01)%
11.	Net (def.) / suff.	(533.0)	(2,069.5)	(2,514.8)
12.	Gross (def.) / suff.	(801.5)	(3,088.8)	(3,644.6)

Note: Updated to include the effect of changes in provincial income and capital tax rates, as outlined in Updated Exhibit C, Tab 1, Schedule 4.

RATE BASE
POWER GENERATION Y-FACTOR CALCULATION

($000's)

Line No.		2008	2009	2010
	Property, plant, and equipment			
1.	Cost or redetermined value	8,272.6	24,734.7	29,855.1
2.	Accumulated depreciation	(98.0)	(781.8)	(1,943.5)
3.		8,174.6	23,952.9	27,911.6
	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	8,174.6	23,952.9	27,911.6

INCOME
POWER GENERATION Y-FACTOR CALCULATION

($000's)

Line No.		2008	2009	2010
	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	288.4	1,034.4	1,242.8
10.	Municipal and other taxes	31.5	43.7	14.0
11.	Total costs and expenses	319.9	1,078.1	1,256.8
12.	**Utility income before inc. taxes**	(319.9)	(1,078.1)	(1,256.8)
	Income taxes			
13.	Excluding interest shield	(285.0)	(474.2)	(473.8)
14.	Tax shield on interest expense	(121.3)	(350.2)	(383.3)
15.	Total income taxes	(406.3)	(824.4)	(857.1)
16.	**Ontario utility net income**	86.4	(253.7)	(399.7)

Note: Updated to include the effect of changes in provincial income and capital tax rates, as outlined in Updated Exhibit C, Tab 1, Schedule 4.

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

($000's)

Line No.		2008	2009	2010
1.	Utility income before income taxes	(319.9)	(1,078.1)	(1,256.8)
	Add Backs			
2.	Depreciation and amortization	288.4	1,034.4	1,242.8
3.	Large corporation tax	-	-	-
4.	Other non-deductible items	-	-	-
5.	Any other add back(s)	-	-	-
6.	Total added back	288.4	1,034.4	1,242.8
7.	Sub total - pre-tax income plus add backs	(31.5)	(43.7)	(14.0)
	Deductions			
8.	Capital cost allowance - Federal	433.0	1,034.1	1,180.4
9.	Capital cost allowance - Provincial	433.0	1,034.1	1,180.4
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	386.4	359.3	334.2
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-
15.	Any other deduction(s)	-	-	-
16.	Total Deductions - Federal	819.4	1,393.4	1,514.6
17.	Total Deductions - Provincial	819.4	1,393.4	1,514.6
18.	Taxable income - Federal	(850.9)	(1,437.1)	(1,528.6)
19.	Taxable income - Provincial	(850.9)	(1,437.1)	(1,528.6)
20.	Income tax provision - Federal	(165.9)	(273.0)	(275.1)
21.	Income tax provision - Provincial	(119.1)	(201.2)	(198.7)
22.	Income tax provision - combined	(285.0)	(474.2)	(473.8)
23.	Part V1.1 tax	-	-	-
24.	Investment tax credit	-	-	-
25.	Total taxes excluding tax shield on interest expense	(285.0)	(474.2)	(473.8)
	Tax shield on interest expense			
26.	Rate base as adjusted	8,174.6	23,952.9	27,911.6
27.	Return component of debt	4.43%	4.43%	4.43%
28.	Interest expense	362.1	1,061.1	1,236.5
29.	Combined tax rate	33.500%	33.000%	31.000%
30.	Income tax credit	(121.3)	(350.2)	(383.3)
31.	**Total income taxes**	(406.3)	(824.4)	(857.1)

Note: Updated to include the effect of changes in provincial income and capital tax rates, as outlined in Updated Exhibit C, Tab 1, Schedule 4.

REVENUE REQUIREMENT
POWER GENERATION Y-FACTOR CALCULATION

($000's)

Line No.		2008	2009	2010
	Cost of capital			
1.	Rate base	8,174.6	23,952.9	27,911.6
2.	Required rate of return	7.58%	7.58%	7.58%
3.	Cost of capital	619.6	1,815.6	2,115.7
	Cost of service			
4.	Gas costs	-	-	-
5.	Operation and Maintenance	-	-	-
6.	Depreciation and amortization	288.4	1,034.4	1,242.8
7.	Municipal and other taxes	31.5	43.7	14.0
8.	Cost of service	319.9	1,078.1	1,256.8
	Misc. & Non-Op. Rev			
9.	Other operating revenue	-	-	-
10.	Other income	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-
	Income taxes on earnings			
12.	Excluding tax shield	(285.0)	(474.2)	(473.8)
13.	Tax shield provided by interest expense	(121.3)	(350.2)	(383.3)
14.	Income taxes on earnings	(406.3)	(824.4)	(857.1)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	(801.5)	(3,088.8)	(3,644.6)
16.	Net (def.) / suff.	(533.0)	(2,069.5)	(2,514.8)
17.	Taxes on (def.) / suff.	268.5	1,019.3	1,129.8
18.	**Revenue requirement**	801.7	3,088.6	3,645.2
	Revenue at existing Rates			
19.	Gas sales	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0
22.	Rounding adjustment	0.2	(0.2)	0.6
23.	Revenue at existing rates	0.2	(0.2)	0.6
24.	**Gross revenue (def.) / suff.**	(801.5)	(3,088.8)	(3,644.6)

Note: Updated to include the effect of changes in provincial income and capital tax rates, as outlined in Updated Exhibit C, Tab 1, Schedule 4.

Y FACTOR DEMAND-SIDE MANAGEMENT

1. The Board convened the EB-2009-0154 proceeding to review and approve the Company's DSM Plan for 2010. On May 13, 2009, the Company was instructed in a letter from the Board to "remove the parts of their DSM budgets, targets, shareholder incentives and programs related to low income energy consumers from their main [DSM] portfolio." A Low-Income Energy Assistance Program ("LEAP") Conservation Working Group was established to develop a separate short term DSM framework for Low Income consumers over the July-August 2009 period.

2. On September 28, 2009, in response to direction from the Ministry of Energy and Infrastructure, the Board instructed the Company to revert back to the existing DSM framework for low-income programs, to be addressed in a second phase of EB-2009-0154.

3. The proposed budget for 2010 DSM in the EB-2009-0154 proceeding, prior to inclusion of targeted low-income, was $25,050,770. The proposed budget for 2010 DSM inclusive of targeted low-income is $26,717,750 which represents an increase of $1,666,980 to be allocated to existing low-income DSM programs in 2010. The revised 2010 DSM budget is calculated using the formula and escalation factor prescribed in EB-2006-0021 Decision, and is consistent with the request of the Board in its September 28, 2009 letter (see Table 1 below for detailed budget calculation). Enbridge will file evidence in support of this budget by the October 15, 2009 deadline specified in that letter.

4. In addition to the prescribed "status quo" low income budget for 2010, Enbridge is requesting Board approval to add an incremental $1.4 million to its low-income DSM

budget to take advantage of a time-sensitive opportunity in the market to install 200 solar thermal water heaters in social housing units at a reduced cost, that may only be available until the end of 2010. This would increase the DSM budget of $26,717,750 (outlined in par. 3 above) to $28,117,750 (see Table 1).

5. The timing of these installations in 2010 is significant due to a number of financial incentives that are available during that year that may not be available in subsequent years. Firstly, Enbridge can offer approximately $2,500 in savings off the installed cost as a result of Enbridge's operational involvement in developing and delivering the Government of Canada's ecoENERGY for Renewable Heat program. These program incentives are secured until December 2010. Secondly, solar thermal installations in 2010 will also qualify for the Federal Government's ecoENERGY Retrofit – Homes program rebate and the Provincial Government's Home Energy Savings program rebates, which amount to an additional $2,500 off the installed cost of solar thermal water heating units.[1]

6. Enbridge has carefully reviewed the direction of the Board in its September 28, 2009 letter regarding low-income DSM programs, and is sensitive to the rationale behind this request; that any new support programs for low-income DSM should be postponed until the Ministry produces its province-wide integrated program for low-income consumers. However, given the unique opportunity Enbridge has in 2010 with the availability of time-limited financial incentives, and given the Ministry's well-documented support of renewable energy options for Ontarians, Enbridge

[1] These latter two rebates are not assumed in the $1.4 million budget request, pending execution of legal agreements with the Federal and Provincial governments to direct rebate dollars back to the utility. However, Enbridge has received verbal indication from Government staff at both levels that they are agreeable to this arrangement. In the event that these government rebates can be accessed, the budget requirement would be reduced from $1.4 million to $0.9 million with the difference being recorded in the DSMVA.

respectfully requests that the Board consider approval of this focused initiative to install 200 solar thermal water heating units in social housing in 2010, at a cost of $1.4 million.

7. Enbridge will submit additional detailed evidence in support of the $1.4 million budget request for solar thermal installations along with the evidence in support of the status quo low-income budget ($1,666,980) by October 15, 2009.

TABLE 1

Budget Category	2009 Board-Approved DSM Budget (EB-2006-0021)	2010 DSM Budget (filed in EB-2009-0154)	2010 DSM Budget (revised for EB-2009-0154 Phase 2)
Base DSM Portfolio	$24,255,000 (includes low-income)	$23,800,770 (excludes low-income)	$25,467,750 (includes status quo low-income) [1 2]
Proposed Industrial Support Pilot Program	$0	$1,250,000	$1,250,000
Sub Total	$24,255,000	$25,050,770	$26,717,750
New Low Income Solar Thermal Proposal	$0	$0	$1,400,000
Total DSM	$24,255,000	$25,050,770	$28,117,750

[1] Represents 5% increase over 2009 Board Approved DSM Budget

[2] Includes a status quo low-income budget of $1,666,980 ($25,467,750 - $23,800,770)

Witnesses: A. Mandyam
P. Squires

UPDATED EVIDENCE

8. As a result of the Board's Decision in the EB-2009-0154 DSM Phase II proceeding, the Company has revised its DSM Y factor amount for the 2010 Test Year to reflect the removal of the $1.4 Million Low-Income Solar Thermal Water Heat program as shown in Table 2 below.

TABLE 2

Budget Category	2009 Board-Approved DSM Budget (EB-2006-0021)	2010 DSM Budget (filed in EB-2009-0154)	2010 DSM Budget (revised for EB-2009-0154 Phase 2)
Base DSM Portfolio	$24,255,000 (includes low-income)	$23,800,770 (excludes low-income)	$25,467,750 (includes status quo low-income) [1 2]
Proposed Industrial Support Pilot Program	$0	$1,250,000	$1,250,000
Sub Total	$24,255,000	$25,050,770	$26,717,750
New Low Income Solar Thermal Proposal	$0	$0	0
Total DSM	$24,255,000	$25,050,770	$26,717,750

[1] Represents 5% increase over 2009 Board Approved DSM Budget

[2] Includes a status quo low-income budget of $1,666,980 ($25,467,750 - $23,800,770)

Witnesses: A. Mandyam
P. Squires

Not Used

Y FACTOR GREEN ENERGY INITIATIVES

WITHDRAWN

Y FACTORS - OTHER

1. This evidence supports the Company's Y-factor adjustments for gas in storage related carrying costs and CIS / Customer Care costs, found within the revenue per customer cap formula evidence at Exhibit B, Tab 1, Schedule 2, page 1. Evidence supporting the Y-factors for DSM, power generation projects, and Green Energy Initiatives can be found in Exhibit B, Tab 2, Schedules 1 through 4.

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 (Ref. Exhibit E, Tab 2, Schedule 1); and

   b. Incremental gas costs associated with upstream transportation, storage and supply mix costs relative to the Company's 2010 volumetric forecast. The Company's current 2010 forecast of gas costs to operations is found at Exhibit B, Tab 6, 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 2009 costs from rates and replace them with the costs associated with the 2010 forecast carrying costs and related working cash that result from the changes inherent in the gas volume budget and associated gas in storage balance. Please refer to Exhibit B, Tab 1, Schedule 2, Appendix A for calculation details.

Witness: K. Culbert

2010 PENSION FUNDING REQUIREMENT

Background

1. Enbridge has historically accounted for pension costs on a flow-through basis. In other words, 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, the costs so determined 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 reported financial statements.

3. EGD's main pension plan ("the plan" or "EGD's plan") is a registered pension plan and is subject to the Pension Benefits Act (Ontario) ("PBAO"). The plan has defined benefit ("DB") and defined contribution ("DC") components. In respect of asset values or funding status, this evidence primarily addresses the DB component of the plan, which represents approximately 99% of the plan assets. The plan had been in a surplus in recent years[1], thus precluding EGD from making any contributions to the plan. As a result of the surplus, EGD's base year (2007) costs in its current incentive regulation term and the corresponding revenue requirement

[1] Surplus in recent years shown in Appendix A

did not include any amounts relating to pension costs for the plan, resulting in a significant benefit to ratepayers over multiple years. This benefit was also available to ratepayers in the period prior to the onset of IR. The estimated annual benefit may be quantified as the annual employee service cost, which has averaged approximately $13 million annually, in recent years. Thus, the benefit experienced by ratepayers, in the form of reduced revenue requirement in the past five years alone has been approximately $65 million.

4. The status of the plan is determined with reference to actuarial valuations ("valuations") conducted by Mercer (Canada) Limited ("Mercer"), the actuarial firm retained by the Company for the plan. EGD requires Mercer to conduct 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. The funded status of the plan (i.e., the surplus or deficit reflected in the most recent filing with FSCO) determines the need for contributions to the plan. EGD filed its last actuarial valuation with FSCO as at December 31, 2006. The December 31, 2006 valuation indicated a significant surplus, thus precluding EGD from making any contributions to the plan. EGD must file its next valuation as at December 31, 2009 in order to remain compliant with the PBAO.

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 situation results in a deficit.

7. This evidence has been written based on the results of the last annual valuation completed by Mercer as at December 31, 2008.

Recent events and their impact

8. Notwithstanding the significant plan surplus reported at the time of the last filing with FSCO, recent turmoil in the financial markets has resulted in erosion of the entire plan surplus, based on the most recent valuation completed as at December 31, 2008.

9. The financial and economic downturn over the past year has been monumental, not only significantly impacting financial markets around the globe but also causing a severe economic decline. The credit squeeze that led to the failure of scores of financial institutions in North America greatly contributed to the crisis. Investments in almost every variety of financial instruments were adversely impacted. The shelter ordinarily provided by well diversified and balanced portfolios was also limited, given that almost all sectors of the economy were in decline.

10. The fair-value of assets held by the EGD plan was also adversely impacted by the financial crisis. As a result, the plan's going-concern surplus of $187 million as at December 31, 2007 (on a liability base of $616 million) turned into a deficit of over $2 million only one year later. However, on a solvency basis, the plan remained in a surplus position, although the amount of the surplus was a small fraction of the 2007 surplus (see Appendix A). Ordinarily, the magnitude of the surplus that existed as at December 31, 2007 would have circumvented the need for additional contributions for the foreseeable future, but for the sudden and dramatic downturn in financial markets, particularly during the latter part of 2008.

11. Taking into account the status of the plan as at December 31, 2008 and given the typical annual increase in liability that will arise from employee service rendered during 2009, it is anticipated, based on actuarial estimates, that the valuation required to be completed as at December 31, 2009 will likely show a plan deficit, which will trigger the requirement for contributions to the plan during 2010. As indicated earlier, the Company is required by FSCO to file the 2009 valuation.

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 plan starting in 2010. Based on the December 31, 2008 valuation, Mercer had estimated that EGD would need to make annual contributions of $17.1 million and pay an annual Pension Benefits Guarantee Fund (“PBGF”) premium of $1.8 million in 2010, for a total of $18.9 million relating to EGD employees.

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 the current rate application.

14. To assist with the preparation of this evidence, the Company requested Mercer to prepare a forecast of the plan’s actuarial valuation as at December 31, 2009 (based on information available as at August 31, 2009). Mercer’s “best estimate” forecast of the plan’s position as at December 31, 2009 suggests that the plan’s funding position may improve (as compared to the December 31, 2008 valuation) to the point where contributions will drop to $1.5 million in 2010, but that the Company will remain liable for the PBGF premium payment of an amount of $1.5 million, for a total cost of $3.0 million.

15. However, it must be noted that Mercer's forecast valuation is an estimate only and was based on information available at a point in time (August 31, 2009). The Company's actual contribution requirements for 2010 will be determined solely by the results of the valuation to be conducted as at December 31, 2009. Again, based on information known at this time, it appears that the cost implications are in the range, but not limited to (pending the year-end valuation), amounts in the order of $3.0 million to $18.9 million.

16. EGD has made an assessment of the applicability of Z factor criteria (as defined in EB-2007-0615 – Exhibit N1, Tab 1, Schedule 1) to this element of cost. This assessment is provided later in this evidence.

<u>Evaluation of criteria for Z-factor</u>

17. The following are criteria to be met for Z-factor treatment as defined in EB-2007-0615 – Exhibit N1, Tab 1, Schedule 1:

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 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).

18. 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*:

19. As described earlier in this evidence, recent turmoil in the financial markets has resulted in a significant erosion of the EGD plan's asset value. As at December 31, 2008, the EGD plan had turned to a deficit position on a going-concern basis. Given the expected increase in plan liability arising from employee service rendered during 2009, it is likely that the valuation required to be completed as at December 31, 2009 will show a deficit, which will trigger contribution requirements to ensure compliance with the PBAO and the plan's funding policy.

20. 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:*

21. The "meltdown" in financial markets over the past year was broad-based and it impacted virtually all segments of the economy. Even the most accomplished and experienced managers of plan assets could not have reasonably anticipated the events that resulted in the world-wide economic downturn and the resulting crash of financial markets. These events were clearly beyond the control of and could not have been reasonably foreseen by EGD's management.

22. 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.

23. The Company believes that the significant losses in the financial markets could not have been anticipated and that the Enbridge pension governance structure in place ensured a prudent response to events as they unfolded. Thus, the risk mitigation measures in place were consistent with the actions of a prudent utility.

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

24. 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.

iv. Any cost increase must be prudently incurred:

25. EGD's estimated annual funding requirement of $18.9 million (based on the December 31, 2008 valuation) arises from the PBAO and primarily includes employee service cost related contributions. The estimated funding amount is based upon the "solvency" liabilities of the plan. The PBAO requires pension plans to fund "solvency" liabilities, not "wind-up" liabilities; however, "wind-up" liabilities may be funded at an employer's discretion.

26. The cost increase arises from the Company's duty to comply with the PBAO and the plan's funding policy, thus satisfying the prudence criteria.

Witnesses: J. Haberbusch
N. Kishinchandani

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).*

27. The anticipated cost increase for 2010 is expected to be $18.9 million, significantly higher than the threshold of $1.5 million.

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

28. As noted above, the Company's projected pension funding liability meets the Z-factor criteria. The exact 2010 pension cost will be determined based on the actuarial valuation of the plan conducted as at December 31, 2009, which will become available no earlier than April 2010.

29. EGD proposes that the estimated pension cost of $18.9 million 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 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.

30. Once the valuation at December 31, 2009 becomes available and the contribution requirement in 2010 (i.e. pension cost) becomes known, any variance from the estimated cost of $18.9 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.

31. As noted above in this evidence, Mercer's current forecast (based on information available as at August 31, 2009) suggests that the Company's contribution requirements during 2010 may be significantly lower than those which would have

been required under the December 31, 2008 valuation, and may be as low as $3.0 million. However, this is an estimate based on information available at a specific point in time (August 31, 2009) and will change with the performance of financial markets over the remainder of 2009. The proposed variance account will ensure that ratepayers are held whole for any changes in contribution requirements that ultimately occur.

32. The pension cost for years subsequent to 2010 will be the subject matter of future rate applications. Given the transition from CGAAP to International Financial Reporting Standards effective 2011, the Company will consider the impacts of such transition on its financial statements and, if deemed appropriate, will request necessary changes to rate-setting in the context of pension costs, as part of its 2011 rate application.

Summary

33. 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

34. 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, the plan's funding policy and accounting guidelines.

Witnesses: J. Haberbusch
N. Kishinchandani

35. In light of the above, the Company respectfully requests Board approval for inclusion of $18.9 million in pension costs as a Z-factor in its revenue requirement for 2010. In addition, the Company requests that the Board approve the establishment of a pension costs variance account.

Witnesses: J. Haberbusch
N. Kishinchandani

Appendix A

EGD - Registered Pension Plan

($ millions)	2008	2007	2006	2005	2004
Going-Concern basis					
Defined Benefit assets	628.2	802.3	821.2	767.3	706.3
Defined Benefit liabilities	630.6	615.6	614.4	576.6	529.7
Funding excess / (deficit)	**(2.4)**	**186.7**	**206.8**	**190.7**	**176.6**
Solvency / Wind-up basis					
Defined Benefit assets	627.6	801.7	820.6	766.7	705.7
Defined Benefit liabilities	605.2	664.8	640.9	631.0	562.0
Solvency / Wind-up excess[1]	**22.4**	**136.9**	**179.7**	**135.7**	**143.7**
Expected rate of return on assets	6.00%	5.75%	5.85%	6.20%	6.40%
Actual rate of return on assets	-18.28%	0.98%	10.62%	13.11%	10.85%
Excess / (shortfall) return	-24.28%	-4.77%	4.77%	6.91%	4.45%
Impact on plan assets	(191.3)	(38.5)	35.9	47.8	28.8

[1] Defined Benefit liabilities for 2008 have been calculated on a solvency basis, the most favourable scenario permitted under the PBAO. For years prior to 2008, given the significant surplus in the plan, these have been calculated only on a wind-up basis, the most conservative view. The wind-up basis financial position indicated a deficiency of ($62.5) million for 2008.

Witnesses: J. Haberbusch
N. Kishinchandani

Z-FACTOR REQUEST RELATED TO CROSSBORES/SEWER LATERALS

1. The Company requests the establishment of a 2010 Z-factor to allow the recovery in rates of costs related to Enbridge's Sewer Lateral Initiative. As the total amount of these costs cannot be precisely forecast at this time, the Company also requests the establishment of a variance account, to record differences between the costs incurred and the amount forecast in the Z-factor.

2. As set out in detail below, Enbridge's Sewer Lateral Initiative is a project to identify and rectify potentially dangerous installations where an existing gas line is installed through an existing sewer lateral line (a crossbore) and to avoid new crossbores in ongoing work. It is only in recent years that the potential magnitude of this problem has become known. It is clear that Enbridge must take steps to address the issue. Enbridge has now developed a plan to address the issue. The 2010 costs associated with the Sewer Lateral Initiative are forecast at $5.7 million (comprised of $3.5 million in Operations & Maintenance costs and $2.2 million in capital costs). Based on these costs, the amount of the 2010 Z-factor revenue requirement is approximately $3.6 million.

(a) The Crossbores/Sewer Laterals Issue

3. A crossbore is an unintended intersection of an existing utility by a second utility that can occur during trenchless construction. Stated differently, it is where one utility pipe unintentionally damages another compromising the integrity of either or both utility facilities.

4. Generally speaking, the crossbores that involve Enbridge pipes are intersections where Enbridge's lines unintentionally pass through sewer lines, with this evidence focusing on Enbridge lines through sewer lateral lines. The crossbores 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. 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.

5. 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 they have inadvertently led to crossbores because municipalities typically do not have records of the location of sewer laterals and therefore they do not locate them when a locate is requested prior to the trenchless installation.

6. 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.

7. 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 lateral, and a natural gas crossbore 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.

8. Typically the municipality owns the sewer lateral up to the property line and the property owner owns the remaining portion to the building. Often, municipalities do not have records of the location of sewer laterals and they do not provide locates when they are requested. Typical homeowners may not know where their portion of the sewer lateral is buried, or have the expertise to locate it.

9. While the potential safety issues related to crossbores have been known for some time, in recent years the importance and urgency of the crossbore issue has grown significantly. In the past several years, there have been tragic incidents involving other utilities.

10. In May 2004, Enbridge's affiliate St. Lawrence Gas (SLG) experienced an incident which resulted in an explosion and fatality at a customer's home in Ogdensburg, New York. It was determined that a gas line was inadvertently installed through the customer's sewer lateral several years earlier. As a result of the incident, SLG revised their construction procedures for trenchless technologies to prevent creation of crossbore situations going forward. Also, since the incident, SLG has worked with the municipalities, plumbers and the public to educate them with respect to the potential hazard and to encourage them to report problems with blocked sewers to SLG in advance of using auguring equipment in a sewer lateral.

11. Enbridge is aware of 21 explosions in the United States that have resulted from crossbore situations involving natural gas lines. Many of these incidents have caused serious personal injury and property damage. Many of these incidents have occurred in the last few years.

12. During 2007, Enbridge began activities to attempt to identify areas in its franchise that could be susceptible to crossbores, and to evaluate how potential crossbores could be investigated as efficiently as possible. In mid 2007, Enbridge responded to a serious situation in its franchise area, when a plumber encountered a crossbore and pierced a natural gas line. Fortunately, the natural gas did not enter the home. Since that time, Enbridge has repaired at least 13 more sewer lateral crossbores that were reported by homeowners, plumbers, municipalities or found by Enbridge in its franchise area.

13. In February 2008, Enbridge representatives participated in the first AGA Conference on "Managing the Threat of Sewer Facilities on Trenchless Installations" which was an audio conference. The audio conference and further discussions with other utility representatives demonstrated that some had made further progress on this issue relative to Enbridge.

14. At or about the same time, Enbridge received the results of an AGA survey that set out approaches taken by other gas distribution utilities to address crossbore issues. These approaches were considered and adapted for application within Enbridge.

15. As a result, it became clear to Enbridge that it must take more proactive steps to address crossbore issues and reduce the chances of any serious incidents in its franchise area. The Technical Standards and Safety Authority ("TSSA") is supportive of efforts to implement a plan to address the crossbore risk.

16. To that end, Enbridge has developed and is now implementing a plan to address the risks of crossbores with sewer laterals. It is this "Sewer Lateral Initiative" which is the subject of the Z-factor request.

(b) <u>Enbridge's Sewer Lateral Initiative</u>

17. The objective of the Sewer Lateral Initiative is to address crossbore risks in both new construction and legacy installations. To do this, Enbridge has implemented new construction methods that are meant to reduce the risk of conflicts between sewer laterals and new gas line installations. Enbridge will also implement programs that aim to identify existing legacy crossbores, so that they can be rectified.

18. To accomplish the first part of this objective, Enbridge has mandated *new construction and excavation techniques* for its installation work. This involves site assessment and, where appropriate, sewer lateral locates, as part of the construction process, to minimize new crossbores. Enbridge implemented these new techniques in the summer of 2008.

19. To accomplish the second part of this objective (to locate and remedy existing legacy crossbores), Enbridge has undertaken and is planning to undertake a number of activities. The fundamental goal of these activities is to raise awareness of the potential safety issue that could arise when attempting to clear a blocked sewer lateral beyond the foundation walls of a building and to attempt to establish a correlation between crossbores and site conditions.

20. Historical activity for a number of years has comprised Enbridge responding to calls received from a homeowner, a plumber, or a municipality, who has identified a possible crossbore. In these cases, Enbridge takes immediate steps to attend at

the site and investigate and, if a crossbore is found, to make appropriate repairs and replacements. As this is not a new activity, Enbridge is not seeking Z-factor treatment for these costs.

21. The Sewer Lateral Initiative also involves a number of new (incremental) activities to locate and remedy existing legacy crossbores.

22. First, Enbridge is taking steps to *investigate* whether crossbores exist at locations that have been identified as having some risk. As noted above, the locations that may be at highest risk of a crossbore are those where sewer laterals are shallow or natural gas lines are deeper than typical. To identify these locations, Enbridge has purchased information from MPAC (Ontario's Municipal Property Assessment Corporation) that identifies which properties in Enbridge's franchise area appear to have shallow or no basements. Enbridge intends to investigate these properties over time, to search for and remedy any crossbores and to confirm whether such conditions actually correlate to an increased risk of crossbores.

23. Second, Enbridge will undertake a *public information campaign* to educate and alert municipalities, plumbers and property owners about the potential existence and danger of crossbores when clearing a blocked sewer lateral beyond the foundation of a building.

24. This will involve a number of activities. One of these will be a series of public meetings, where information and educational materials, will be provided to plumbers in different parts of Enbridge's franchise areas. The first of these public meetings will be held in the Niagara region in late 2009. In advance of that time, Enbridge will send letters to tradespeople working with plumbing and drains in the area, explaining the potential issue with crossbores, and inviting them to an open house

breakfast to explain Enbridge's new procedures to assist with avoiding potential crossbore issues. Enbridge plans to expand this effort into its other franchise areas in 2010.

25. Enbridge also plans to publicize the issue through bill inserts that will alert homeowners 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 crossbores.

26. The goal of these activities is to have plumbers and others using mechanical auger equipment or other means to clear blocked sewer lines call Ontario One Call to request a gas locate 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 gas line locate, which in most cases will confirm that there is no crossbore 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.

27. Third, 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 crossbore. 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 CIS is fully operational and stable. At the same time, information can be included about properties that are not at risk for crossbores because trenchless installation methods were not used.

28. Fourth, Enbridge will undertake *research and development efforts* to identify and create new and more cost-effective methods for locating sewer laterals and crossbores.

29. In total, the 2010 costs associated with the Sewer Lateral Initiative for which Enbridge seeks Z-factor treatment are budgeted at $5.7 million (comprised of $3.5 million in Operations & Maintenance costs and $2.2 million in capital costs). All of these costs are incremental costs that were not previously necessary or included in Enbridge's budgets at the time that the IRM term commenced. Based on these costs, the amount of the 2010 Z-factor revenue requirement is approximately $3.6 million.

30. Details of Enbridge's forecast of 2010 activities and costs of its Sewer Lateral Initiative are set out in Exhibit B, Tab 3, Schedule 2, Appendix A.

31. Enbridge expects that many of the same types of costs will arise again in future years during the IRM term. As appropriate, Enbridge will seek a Z-factor for those costs in future years.

(c) Establishment of Z-factor and Variance Account

32. Based on the foregoing, Enbridge requests the establishment of a Z-factor for 2010, to recover the costs associated with the Sewer Lateral Initiative. As set out at Exhibit B, Tab 3, Schedule 2, Appendix B, page 5 of 5, the amount of the 2010 Z-factor is $3.64 million.

33. The Sewer Lateral Initiative meets the requirements for the establishment of a Z-factor set out in the IRM Settlement Agreement. For example,

(a) it entails an increase in Enbridge's costs beyond those included or contemplated in the base that was set for IRM (these are new activities, and the costs included in the Z-factor relate to new, not existing, resources);

(b) these costs are unexpected in that the need for a comprehensive program to address crossbore issues was not known or anticipated at the time of the proceeding that led to the framework for IRM;

(c) the costs are beyond the control of Enbridge's management in that these activities are necessary to address emerging safety concerns;

(d) the activities are required to be undertaken in 2010, and the associated costs are prudent and reasonable;

(e) customers previously benefited from lower costs associated with trenchless installations - the cost of the Sewer Lateral Initiative that Enbridge seeks to recover through the Z-factor is a related unforeseen cost that has now arisen; and

(f) the total 2010 costs exceed the Z-factor threshold.

34. The budgeted costs that underlie the Z-factor request are, in large part, based upon Enbridge's forecast of the level of locate-type activity that will be necessary in 2010 due to educating plumbers and the public about crossbore risk.

35. It is clear, though, that the level of activity (and therefore costs) cannot be known with any degree of certainty until the Sewer Lateral Initiative is up and running.

36. In particular, the level of activity as a result of the public information campaign is difficult to forecast. Factors that affect the public information campaign and follow-up costs will include, but are not limited to, the number of blocked sewer calls, the

time and costs associated with Enbridge determining whether a conflict exists, the number of excavations required, the number of crossbores found and the overall success rate of the campaign itself.

37. Enbridge proposes, therefore, that a variance account be established to track actual 2010 costs associated with the Sewer Lateral Initiative. This variance account would track differences between actual costs and the costs that are recovered through the Z-factor, and ensure that it is only the costs actually incurred that are ultimately recovered from ratepayers.

2010 FORECAST COSTS OF SEWER LATERAL INITIATIVE

1. Details of Enbridge's forecast of 2010 costs related to each of the constituent elements of its Sewer Lateral Initiative are set out below.

2. For each element, a chart is presented which sets out the categories of costs, whether the costs are capital or O&M, and the total cost of that element.

   a. New construction and excavation techniques

Expenditure Description	Expenditure Type	Expenditure Cost	Total Volume of Work
Sewer Lateral Locate - Perform sewer lateral locates.	Capital	$1,232,617	6555
Transition Holes - Excavations required to maintain minimum depth during the installation of mains and services.	Capital	$123,894	3520
Daylight Witness Holes - Excavations required to determine that minimum clearances are maintained at sewer lateral crossing locations.	Capital	$51,833	880
Site Specific Construction - Additional construction costs incurred when sewer lateral locates are unsuccessful.	Capital	$91,656	3605
Total Cost		$1,500,000	

Witnesses: J. Haberbusch
N. Kishinchandani

b. Investigate and address potential crossbore locations

Expenditure Description	Expenditure Type	Expenditure Cost	Total Volume of Work
Sewer Lateral Investigations - Perform video inspection of sewer laterals.	O&M	$766,145	1817
Performance Standard Inspector Investigation - Perform gas locates and site verifications for areas where sewer lateral investigations were not possible.	O&M	$33,311	999
Daylighting Inspections - Excavate and inspect areas of possible crossbores where sewer lateral investigations are not possible.	O&M	$33,311	91
Relocations, Relays, Pipe Replacements - Complete work when a crossbore is found.	Capital	$131,571	26
Total Cost		$964,338	

c. Public information campaign and follow-up

Expenditure Description	Expenditure Type	Expenditure Cost	Total Volume of Work
Ontario One Call Services - Call centre services to take call and dispatch appropriate locate service provider.	O&M	$21,400	8646
Emergency Natural Gas Locate - The completion of a natural gas locate on an emergency basis.	O&M	$403,500	8646
Ontario One Call Services - Call centre services to take call and dispatch appropriate locate service provider.	Capital	$2,378	8646
Emergency Natural Gas Locate - The completion of a natural gas locate on an emergency basis.	Capital	$44,850	8646
Emergency Sewer Lateral Investigation - The completion of an emergency sewer lateral inspection and/or utility clearance process.	O&M	$1,073,040	1729
Daylighting Inspections - Excavate and inspect areas of possible crossbores where sewer lateral investigations are not possible or are inconclusive.	O&M	$172,000	86
Potential Claims and Program Incentives - The compensation that will be sought by plumbers/drain cleaners/homeowners for standby time.	O&M	$683,000	4700
Education Materials - All publicity materials, public meeting and mailing costs.	O&M	$300,000	2000000
Total Cost		$2,700,168	

d. IT upgrades and tracking

Expenditure Description	Expenditure Type	Expenditure Cost
System change required to record the method used to install the service line.	Capital	$13,000
System change required to record method of installation between nodes of every section of main.	Capital	$21,000
System change required for record system to be used to track the inspection work/areas completed during the sewer lateral investigation.	Capital	N/A
I.T. Maintenance of Sewer Lateral Programs - Required server maintenance to sewer lateral storage servers.	O&M	$10,000
Sewer Lateral Clearance Tracking - The addition of resources to record sewer lateral clearance in the GIS system and to investigate as-laid construction drawings for construction method.	O&M	$50,100
Sewer Lateral Clearance Tracking - The addition of resources to record sewer lateral clearance in the GIS system and to investigate as-laid construction drawings for construction method.	Capital	$144,900
System change required to create job codes necessary to send sewer lateral investigative contractors out on emergency investigations.	Capital	$14,000
Total Cost		$253,000

Witnesses: J. Haberbusch
N. Kishinchandani

e. Research and development efforts

Expenditure Description	Expenditure Type	Expenditure Cost
Research and development of Sewer Lateral locating technologies - Research and develop safe and more cost-effective methods of locating sewer laterals.	Capital	$300,000
Total Cost		$300,000

5817525.1

CAPITAL STRUCTURE
CROSSBORES / SEWER LATERALS Z-FACTOR CALCULATION

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

	($000's)	2010
7.	Ontario Utility Income	(2,440.9)
8.	Rate base	930.7
9.	Indicated rate of return	(262.26)%
10.	(Def.) / suff. in rate of return	(269.84)%
11.	Net (def.) / suff.	(2,511.4)
12.	Gross (def.) / suff.	(3,639.7)

Note: Updated to include the effect of changes in provincial income and capital tax rates, as outlined in Updated Exhibit C, Tab 1, Schedule 4.

RATE BASE
CROSSBORES / SEWER LATERALS Z-FACTOR CALCULATION

($000's)

Line No.		2010
	Property, plant, and equipment	
1.	Cost or redetermined value	944.8
2.	Accumulated depreciation	(14.1)
3.		930.7
	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	930.7

INCOME

CROSSBORES / SEWER LATERALS Z-FACTOR CALCULATION

($000's)

Line No.		2010
	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	3,545.8
9.	Depreciation and amortization	41.6
10.	Municipal and other taxes	1.6
11.	Total costs and expenses	3,589.0
12.	**Utility income before inc. taxes**	(3,589.0)
	Income taxes	
13.	Excluding interest shield	(1,135.3)
14.	Tax shield on interest expense	(12.8)
15.	Total income taxes	(1,148.1)
16.	**Ontario utility net income**	(2,440.9)

Note: Updated to include the effect of changes in provincial income and capital tax rates, as outlined in Updated Exhibit C, Tab 1, Schedule 4.

TAXABLE INCOME AND INCOME TAX EXPENSE
CROSSBORES / SEWER LATERALS Z-FACTOR CALCULATION

($000's)

Line No.		2010
1.	Utility income before income taxes	(3,589.0)
	Add Backs	
2.	Depreciation and amortization	41.6
3.	Large corporation tax	-
4.	Other non-deductible items	-
5.	Any other add back(s)	-
6.	Total added back	41.6
7.	Sub total - pre-tax income plus add backs	(3,547.4)
	Deductions	
8.	Capital cost allowance - Federal	114.6
9.	Capital cost allowance - Provincial	114.6
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	114.6
17.	Total Deductions - Provincial	114.6
18.	Taxable income - Federal	(3,662.0)
19.	Taxable income - Provincial	(3,662.0)
20.	Income tax provision - Federal	(659.2)
21.	Income tax provision - Provincial	(476.1)
22.	Income tax provision - combined	(1,135.3)
23.	Part V1.1 tax	-
24.	Investment tax credit	-
25.	Total taxes excluding tax shield on interest expense	(1,135.3)
	Tax shield on interest expense	
26.	Rate base as adjusted	930.7
27.	Return component of debt	4.43%
28.	Interest expense	41.2
29.	Combined tax rate	31.000%
30.	Income tax credit	(12.8)
31.	**Total income taxes**	(1,148.1)

Note: Updated to include the effect of changes in provincial income and capital tax rates, as outlined in Updated Exhibit C, Tab 1, Schedule 4.

REVENUE REQUIREMENT
CROSSBORES / SEWER LATERALS Z-FACTOR CALCULATION

($000's)

Line No.		2010
	Cost of capital	
1.	Rate base	930.7
2.	Required rate of return	7.58%
3.	Cost of capital	70.5
	Cost of service	
4.	Gas costs	-
5.	Operation and Maintenance	3,545.8
6.	Depreciation and amortization	41.6
7.	Municipal and other taxes	1.6
8.	Cost of service	3,589.0
	Misc. & Non-Op. Rev	
9.	Other operating revenue	-
10.	Other income	-
11.	Misc, & Non-operating Rev.	-
	Income taxes on earnings	
12.	Excluding tax shield	(1,135.3)
13.	Tax shield provided by interest expense	(12.8)
14.	Income taxes on earnings	(1,148.1)
	Taxes on (def) / suff.	
15.	Gross (def.) / suff.	(3,639.7)
16.	Net (def.) / suff.	(2,511.4)
17.	Taxes on (def.) / suff.	1,128.3
18.	**Revenue requirement**	3,639.7
	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.**	(3,639.7)

Note: Updated to include the effect of changes in provincial income and capital tax rates, as outlined in Updated Exhibit C, Tab 1, Schedule 4.

2010 PROPOSED RATES

1. This evidence outlines the Company's proposal with respect to 2010 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 2010 rates including the proposed recovery of the 2010 revenue requirement.

2. The Company is seeking Board approval of each of the following:
    a. recovery of the 2010 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 4, Schedule 2.

3. The Rate Handbook filed under Exhibit B, Tab 4, Schedule 2 reflects the proposed changes to the rates and the new Direct Purchase Administration Charge ("DPAC"). Except for the proposed rate changes and DPAC structure, all other components of the Rate Handbook filed under this exhibit remain as approved in EB-2009-0309 (October 1, 2009 QRAM).

Components of the 2010 Revenues

4. The derivation of the Company's 2010 revenues reflecting the Revenue Cap per Customer incentive regulation model is presented at Exhibit B, Tab 1, Schedule 2, page 1. Row 30 of that exhibit represents total proposed revenues for 2010 in the amount of $2,456.76 million. /u

Witnesses: J. Collier
A. Kacicnik
M. Suarez

5. As shown at rows 28, 29, and 30, the 2010 proposed revenues consist of:

2010 Distribution Revenues	$1,003.26	/u
2010 Gas Cost to Operations	$1,453.50	
2010 Total Revenues	$2,456.76	/u

6. The 2010 distribution revenues are comprised of: a) 2010 base distribution revenue in the amount of $818.06 million (Row 18), which is determined using the Revenue /u Cap per Customer incentive regulation escalation formula, b) distribution related Y-factor revenues in the amount of $162.70 million (Row 24), and c) distribution /u related Z-factor revenues in the amount of $22.50 million (Row 27).

7. The 2010 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 6, Schedule 2.

2010 Rate Impacts

8. The Company has designed rates to recover the proposed 2010 revenues of $2,456.76 million. Table 1 below provides a summary of the resulting average rate /u 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, 2009 QRAM Board approved rates filed under EB-2009-0309 and reflect the recovery of the proposed 2010 revenue requirement, the proposed 2010 volumetric forecast, and the proposed 2010 Gas Cost to Operations budget.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

Table 1: 2010 Proposed Average Rate Impacts

Rate Class	T-Service Rate Impact
1	1.7%
6	1.2%
9	1.1%
100	0.9%
110	0.9%
115	0.6%
135	0.8%
145	0.9%
170	0.8%
200	0.6%
	Delivery Rate Impact
125	1.0%
300	1.0%

/u

10. The 2010 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.

<u>Rate Design Exhibits</u>

11. Rate design exhibits are filed at Exhibit B, Tab 4, Schedules 3 to 9. The exhibits present the proposed recovery of the 2010 revenues. The schedules are organized in the following manner:

    a) Schedule 3 of Exhibit B, Tab 4 summarizes, by rate class, and rate component, the revenues at proposed rates which are forecast to be recovered in 2010. 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-2009-0309 (October 1, 2009 QRAM) to the proposed unit rates.
    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.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

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-2009-0309 (October 1, 2009 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 2010 forecast of Gas Costs to Operations in the amount of $1,453.5 million including changes to the Company's 2010 gas supply portfolio relative to the 2009 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 Company's QRAM methodology 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, 2009 QRAM rates have a Purchased Gas Variance Account ("PGVA") reference price of $236.950 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 2010 yields a PGVA reference price of $237.160 10^3m^3, which is a slight increase from the October 2009 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 4, Schedule 7 and the allocation of the gas supply revenue requirement is

shown at Exhibit B, Tab 4, 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 2010 distribution revenue requirement of
$818.06 million, which is derived using the proposed Revenue Cap per Customer /u
incentive regulation escalation formula, and distribution revenue requirement of
$162.70 million and $22.50 million associated with the Y-factors and Z-factors /u
respectively.

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 2010 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,

Witnesses: J. Collier
A. Kacicnik
M. Suarez

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: 2010 Proposed Rates

20. In the rate design process, consistent with the approach to design rates in a cost of service environment, the Company used the assignment of the 2010 revenue requirement (Exhibit B, Tab 4, Schedule 10, pp. 1 - 9) as a guide to establish the proposed rates.

21. The Company has designed the proposed 2010 rates while balancing the following objectives: rate stability, rate class characteristics and rate impacts for the various customer classes, market acceptance, continuity, 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 4, Schedule 10, pages 1 and 2.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

<u>Other</u>

<u>System Gas and DPAC Charges</u>

23. Consistent with the Company's evidence and the Board's Decision in EB-2008-0106: Commodity Pricing, Load Balancing and Cost Allocation Methodologies for Natural Gas Distributors in Relation to Regulated Gas Supply, the Company updated the level of incremental costs to support the system gas and direct purchase options. Incremental costs for system gas management are included in the Gas Supply Charge. Incremental costs for direct purchase management are reflected in the DPAC.

24. This update to incremental costs is revenue neutral for Enbridge. In other words, it does not affect the level of revenues derived through the Company's Revenue Cap per Customer incentive regulation formula, but it ensures that an appropriate level of incremental costs is recovered through charges related to supporting system gas and direct purchase options rather than through the Company's delivery rates (which were reduced accordingly). Doing so aligns recovery of costs with the services provided.

25. In addition, the DPAC fee structure has been amended to reflect the Company's evidence in EB-2008-0106. The derivation of the new DPAC charges is shown in the appendix to this schedule. The DPAC charges can also be found in the Rate Handbook under Rider A and Rider B.

<u>Proposed Z-Factors</u>

26. As outlined at Exhibit B, Tab 1, Schedule 2, page 1, the Company is proposing new Z-factors for 2010: (1) Pension funding requirement Z-factor (Row 25), and (2) /u
Crossbores / Sewer Laterals program Z-factor (Row 26).

Witnesses: J. Collier
A. Kacicnik
M. Suarez

27. The Company proposes to allocate the Pension funding requirement proportionally /u
to the allocation of distribution revenue requirement inclusive of Y-factors (but /u
excluding proposed Z-factors) for each rate class as shown at Exhibit B, Tab 4, /u
Schedule 10, page 7, Line 1.7. The revenue requirement for the Crossbores / Sewer Laterals program is allocated equally based on services and low pressure /u
(LP) mains allocators. The allocation of the proposed Z- Factors to each rate class is found at Exhibit B, Tab 4, Schedule 10, page 6.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

Derivation of Proposed Direct Purchase Administration Charge (DPAC):

2010 Incremental Cost to support Direct Purchase option		$2,827,604
Proposed Monthly Fixed Charge	**$75.00**	
2010 Projected number of pools	1,355	
Cost Recovery through Fixed Charge		$1,219,500
2010 Projected number of accounts	644,082	
Proposed Monthly Account Charge	**$0.21**	
Cost Recovery through Account Charge		$1,608,104
Total Recovery		$2,827,604

Notes:

(1) Monthly Fixed Charge is proposed at the same level of Union Gas' DPAC monthly contract fee.

(2) Once the level of recovery through fixed charges has been determined, the account charge is determined by dividing the remaining amount by the projected number of accounts.

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.

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 Baked 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 average 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.

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.

Unless otherwise authorized by the Company in writing, each Applicant taking service pursuant to an OTS-ABC Gas Delivery Agreement shall meet its obligation to deliver gas to the Company by underpinning a minimum percentage and volume of their gas deliveries with firm transport (which in this section is both Firm Transportation and Short Term Firm Transportation) for the winter period commencing January 1 and ending March 31 (the "winter period").

The minimum amounts to be underpinned by firm transport shall be expressed in both volumetric and percentage terms. For the percentage amount, each Applicant shall calculate the annual percentage of gas deliveries to the Company for each of the immediate past three winter periods which were underpinned by firm transport, and taking the average of these three years' percentages, add ten percentage(1) points to the average to establish the minimal amount of gas deliveries that must be underpinned by firm transport for the winter period (e.g., if the average of the past three years is 50% then the addition of ten points will yield 60%(2)).

No later than November 1 of each year and beginning November 1, 2009, each Applicant shall provide written confirmation to the Company of their gas delivery plans for the winter period, including the amounts to be underpinned by firm transport (expressed in both volumetric and percentage terms) as calculated above.

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.

(1) If a direct shipper had no deliveries for a given year, then the calculation should exclude that year; if a direct shipper has less than three winter periods, the calculation will be the average of the periods in which deliveries occurred.
(2) The amount shall not exceed 100%.

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.

RATE NUMBER: 1	RESIDENTIAL 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 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	**$18.00**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**8.7589 ¢/m³**
For the next 55 m³ per month	**8.2371 ¢/m³**
For the next 85 m³ per month	**7.8282 ¢/m³**
For all over 170 m³ per month	**7.5237 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.8119 ¢/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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

RATE NUMBER: 6	GENERAL 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") 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	**$60.00**
Delivery Charge per cubic metre	
For the first 500 m³ per month	**8.0828 ¢/m³**
For the next 1050 m³ per month	**6.3248 ¢/m³**
For the next 4500 m³ per month	**5.0942 ¢/m³**
For the next 7000 m³ per month	**4.3031 ¢/m³**
For the next 15250 m³ per month	**3.9517 ¢/m³**
For all over 28300 m³ per month	**3.8637 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.8974 ¢/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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

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	**$235.15**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**10.8023 ¢/m³**
For all over 20,000 m³ per month	**10.1114 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.6732 ¢/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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

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	**$122.52**
Delivery Charge	
Per cubic metre of Contract Demand	**8.1900 ¢/m³**
For the first 14,000 m³ per month	**5.2144 ¢/m³**
For the next 28,000 m³ per month	**3.8554 ¢/m³**
For all over 42,000 m³ per month	**3.2964 ¢/m³**
Gas Supply Load Balancing Charge	**0.4768 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.7364 ¢/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 average 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): **9.5498 ¢/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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

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	**$589.80**
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	**0.6556 ¢/m³**
For all over 1,000,000 m³ per month	**0.5056 ¢/m³**
Gas Supply Load Balancing Charge	**0.1321 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.6732 ¢/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 average 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):

4.6463 ¢/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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

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	**$625.94**
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	**0.3747 ¢/m³**
For all over 1,000,000 m³ per month	**0.2747 ¢/m³**
Gas Supply Load Balancing Charge	**0.0444 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.6732 ¢/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 average 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: **115**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

4.2777 ¢/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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

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	**9.0984 ¢/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 = 0.7218 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 0.8662 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 1.0593 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, 2010. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates, as the Board Order, EB-2009-0309.

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	**\$115.56**	**\$115.56**
Delivery Charge		
For the first 14,000 m³ per month	**6.8094 ¢/m³**	**2.1094 ¢/m³**
For the next 28,000 m³ per month	**5.6094 ¢/m³**	**1.4094 ¢/m³**
For all over 42,000 m³ per month	**5.2094 ¢/m³**	**1.2094 ¢/m³**
Gas Supply Load Balancing Charge	**0.0000 ¢/m³**	**0.0000 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.7357 ¢/m³**	**19.7357 ¢/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 average 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	**$**	**0.77 /m^3**
Rate per cubic metre of Modified Mean Daily Volume for December	**$**	**0.77 /m^3**

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	**21.4376 ¢/m^3**
January and February	**53.5940 ¢/m^3**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **7.5347 ¢/m^3**

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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

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. 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 72 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	**$123.82**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.9027 ¢/m³**
For the next 28,000 m³ per month	**1.5437 ¢/m³**
For all over 42,000 m³ per month	**0.9847 ¢/m³**
Gas Supply Load Balancing Charge	**0.3593 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.8521 ¢/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	**$**	**0.50 /m³**
Rate for 72 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.11 /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 average 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.

The third instance of such failure 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.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**7.1207 ¢/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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

RATE NUMBER: **170**	**LARGE 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 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, 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	**$279.63**
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	**0.5683 ¢/m³**
For all over 1,000,000 m³ per month	**0.3683 ¢/m³**
Gas Supply Load Balancing Charge	**0.2014 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.6732 ¢/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 average 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.

The third instance of such failure 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.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

4.6284 ¢/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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

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	**1.1899 ¢/m³**
Gas Supply Load Balancing Charge	**0.5132 ¢/m³**
Transportation Charge per cubic metre	**3.9094 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**19.6732 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**19.6508 ¢/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 average 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.

The third instance of such failure 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.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**5.5617 ¢/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, 2010 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the numbered rate schedule that specifies as the effective date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309.

RATE NUMBER: 300	FIRM OR INTERRUPTIBLE DISTRIBUTION 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 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	**24.9784 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3590 ¢/m³**
Maximum Delivery Charge	**0.9854 ¢/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 0.7218 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 0.8662 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 0.6738 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, 2010. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates, as the Board Order, EB-2009-0309.

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 1/24th 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	**0.0539 ¢/m³**
Monthly Storage *Deliverability* Demand Charge	**14.7283 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.3373 ¢/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, 2010. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates, as the Board Order, EB-2009-0309.

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	**0.0539**	**¢/m³**
Monthly Storage *Deliverability* Demand Charge	**5.0698**	**¢/m³**
Injection & Withdrawal Unit Charge:	**0.1174**	**¢/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, 2010.   This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates, as the Board Order, EB-2009-0309.

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	**24.1524 ¢/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, 2010 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates as the Board Order, EB-2009-0309, effective October 1, 2009.

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	**0.1865**	**0.2212**
Maximum Daily Withdrawal Volume	**16.8575**	**20.0617**
Commodity Charge	**1.0776**	**0.3825**

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	**2.4613**	**0.5542**
Unauthorized	**-**	**222.5193**
Pool Storage		
Authorized	**2.9194**	**0.6596**
Unauthorized	**-**	**264.8146**

(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, 2010. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates, as the Board Order, EB-2009-0309.

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	**0.4077**	**0.4077**	**-**
Maximum	**2.0385**	**2.0385**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**36.9192**	**29.5354**	**-**
Maximum	**184.5960**	**147.6768**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**1.4601**	**1.4601**	**0.7229**
Maximum	**7.3005**	**7.3005**	**38.9327**

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.

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		Short Cycle
	Firm	**Interruptible**	
	$/10³m³	**$/10³m³**	**$/10³m³**
Authorized Overrun **Annual Turnover Volume** **Negotiable, not to exceed:**	**38.9327**	**38.9327**	**38.9327**
Authorized Overrun **Daily Injection/Withdrawal** **Negotiable, not to exceed:**	**38.9327**	**38.9327**	**38.9327**
Unauthorized Overrun **Annual Turnover Volume** **Excess Storage Balance**			
September 1 - November 30	**389.3269**	**389.3269**	**389.3269**
December 1 - October 31	**38.9327**	**38.9327**	**38.9327**
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, 2010. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates, as the Board Order, EB-2009-0309.

APPLICABILITY:

To any Applicant who enters into a Contract with the Company for transportation on the Company's Tecumseh Transmission System.

CHARACTER OF SERVICE:

Service under this rate is for firm transportation service 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.

	Firm $/10³m³	Interruptible $/10³m³
Monthly Demand Charge per unit of Maximum Contracted Daily Delivery:	**5.2580**	**-**
Commodity Charge per unit of gas delivered:	**-**	**0.2070**

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges.

TERMS AND CONDITIONS OF SERVICE:

1. Delivery of the volume of natural gas by the Applicant shall be at the interconnection of the Company's Tecumseh transmission facilities with that of Niagara Gas Transmission Limited at the Tecumseh Compressor Station.

2. Re-delivery of the volume of natural gas shall be at the interconnection of the Company's facilities with those of interconnecting pipelines in Dawn Township.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2010. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates, as the Board Order, EB-2009-0309.

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, 2010:

Point of Acceptance	**Firm Transportation (FT)**
CDA, EDA	3.9094 ¢/m^3

<u>TCPL FT CAPACITY TURNBACK:</u>

APPLICABILITY:

To Ontario 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 from customers to the extent that the Company is allowed to turnback FT capacity to TCPL.

2. The Company will accommodate all TCPL FT capacity turnback requests in a manner that minimizes stranded and other transitional costs. The Company is committed to maintaining the integrity of its distribution system and the sanctity of all contracts.

3. The Company may amend any contracts to accommodate a customer's request to turnback capacity.

4. Notice of TCPL FT turnback capacity will be accepted on Enbridge's Election for Enbridge Firm Transportation Assignment form or other authorized written notice.

5. The daily contractual right to receive natural gas would still be subject to the delivery, on a firm basis, of the full Mean Daily Volume into the Company's Central Delivery Area (CDA) and/or Eastern Delivery Area (EDA). The delivery area must match the area in which consumption will occur.

6. The proportion of TCPL FT capacity that an eligible customer may request to be turned back each year ("percentage turnback") shall not exceed the proportion of the TCPL capacity that Enbridge is entitled to turn back that year. This percentage turnback will be applied to calculate the customer's turnback capacity limit based on the renewal volume of the direct purchase agreement.

7. If the Company is unable to accommodate all or a portion of an eligible customer's request to turnback TCPL FT capacity in the month requested by the customer, the Company will indicate the month(s) when such customer request can be fully satisfied and the costs, if any, associated with accommodating this request. The customer may then advise the Company as to whether or not they wish to proceed with the TCPL FT capacity turnback request.

8. All TCPL FT capacity turnback requests will be treated on an equitable basis.

9. Customers may withdraw their original election given they provide notice to the Company a minimum of one week prior to the deadline specified in the TransCanada tariff for FT contract extension.

10. The percentage turnback of TCPL FT capacity will be applied at the Direct Purchase Agreement level.

11. 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, 2010. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates, as the Board Order, EB-2009-0309.

RIDER: B	BUY / SELL SERVICE RIDER

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, 2010. This rate schedule is effective January 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2009 and that indicates, as the Board Order, EB-2009-0309.

Rate Class	Sales Service (¢/m³)	Transportation Service (¢/m³)
Rate 1	0.0000	0.0000
Rate 6	0.0000	0.0000
Rate 9	0.0000	0.0000
Rate 100	0.0000	0.0000
Rate 110	0.0000	0.0000
Rate 115	0.0000	0.0000
Rate 135	0.0000	0.0000
Rate 145	0.0000	0.0000
Rate 170	0.0000	0.0000
Rate 200	0.0000	0.0000

RIDER: E	REVENUE ADJUSTMENT RIDER

The following adjustment shall be applicable to volumes during the period January 1, 2009 to December 31, 2009.

Rate Class	Sales Service (¢/m³)	Transportation Service (¢/m³)
Rate 1	0.0000	0.0000
Rate 6	0.0000	0.0000
Rate 9	0.0000	0.0000
Rate 100	0.0000	0.0000
Rate 110	0.0000	0.0000
Rate 115	0.0000	0.0000
Rate 135	0.0000	0.0000
Rate 145	0.0000	0.0000
Rate 170	0.0000	0.0000
Rate 200	0.0000	0.0000
Rate 300	n/a	-

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	$70.00
For inspection of gas appliances; the Company provides only one inspection free of charge, upon first time introduction of gas to a premise.	
Inspection Reject Charge (safety inspection)	$70.00
Energy Board Inspection rejects are billed to the meter installer or homeowner.	
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	$32.00
For installation of service line beyond allowable guidelines (for new residential services only)	
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	custom quoted
Cut Off At Main charges for commercial services and other residential services that involve significantly more work than the average will be custom quoted.	
Cut Off At Main Charge - Other Customer Requests	$1,300.00
Other residential Cut Off At Main requests due to demolitions, fires, inactive services, etc. will be charged at the standard COAM rate.	
Meter In-Out (Residential Only))	$280.00
Relocate the meter from inside to outside per customer request	
Request For Service Call Information	$30.00
Provide written information of the result of a service call as requested by home owners.	
Temporary Meter Removal	$280.00
As requested by customers.	
Damage Meter Charge	$380.00

RIDER: H	BALANCING SERVICE RIDER

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 a 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

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	$0.7301	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.

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-2009-0172 RATES				
ITEM NO.	RATE NO.	DISTRIBUTION	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL
1.	1	718,691	138,996	30,578	600,420	1,488,686
2.	6	315,190	109,247	27,488	396,043	847,968
3.	9	259	66	0	271	596
4.	100	0	0	0	0	0
5.	110	12,764	4,107	743	8,635	26,249
6.	115	5,751	696	189	856	7,492
7.	125	7,436	0	0	0	7,436
8.	135	1,009	895	(490)	1,166	2,580
9.	145	5,271	2,170	7	5,003	12,452
10.	170	4,896	3,697	(5,453)	15,688	18,828
11.	200	3,804	4,703	666	23,668	32,841
12.	300	491	0	0	0	491
13.	SUB-TOTAL	1,075,562	264,578	53,729	1,051,750	2,445,618
14.	STORAGE	1,632	0	0	0	1,632
15.	DPAC	2,828	0	0	0	2,828
16.	TOTAL	1,080,022	264,578	53,729	1,051,750	2,450,078

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	4,646,080	718,691	15.47	3,555,403	138,996	3.91	4,646,080	30,578	0.66	3,030,604	600,420	19.81	1,488,686
2.	6	4,435,727	315,190	7.11	2,794,436	109,247	3.91	4,435,727	27,488	0.62	1,990,425	396,043	19.90	847,968
3.	9	1,693	259	15.28	1,693	66	3.91	1,693	0	0.00	1,375	271	19.67	596
4.	100	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0
5.	110	562,719	12,764	2.27	105,047	4,107	3.91	562,719	743	0.13	43,892	8,635	19.67	26,249
6.	115	425,510	5,751	1.35	17,804	696	3.91	425,510	189	0.04	4,350	856	19.67	7,492
7.	125	0	7,436	0.00	0	0	0.00	0	0	0.00	0	0	0.00	7,436
8.	135	58,120	1,009	1.74	22,897	895	3.91	58,120	(490)	(0.84)	5,908	1,166	19.74	2,580
9.	145	222,012	5,271	2.37	55,519	2,170	3.91	222,012	7	0.00	25,201	5,003	19.85	12,452
10.	170	543,100	4,896	0.90	94,559	3,697	3.91	543,100	(5,453)	(1.00)	79,744	15,688	19.67	18,828
11.	200	156,140	3,804	2.44	120,305	4,703	3.91	156,140	666	0.43	120,305	23,668	19.67	32,841
12.	300	41,030	491	0.00	0	0	0.00	0	0	0.00	0	0	0.00	491
13	SUB-TOTAL	11,092,131	1,075,562	9.70	6,767,662	264,578	3.9094	11,051,101	53,729	0.49	5,301,806	1,051,750	19.84	2,445,618
14.	STORAGE	N/A	1,632	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,632
15.	DPAC	N/A	2,828	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	2,828
16.	TOTAL	11,092,131	1,080,022	9.70	6,767,662	264,578	3.91	11,051,101	53,729	0.49	5,301,806	1,051,750	19.84	2,450,078

REVENUE - PROPOSED METHODOLOGY BY RATE CLASS

	Col. 1	Col. 2	Col. 3	Col. 4
		REVENUE -EB-2009-0172 RATES		
Item No.	Rate No.	Proposed Revenue	Unbilled Revenue	Total
		($000)	($000)	($000)
1.	1	1,488,686	2,485	1,491,171
2.	6	847,968	4,382	852,350
3.	9	596	0	596
4.	100	0	0	0
5.	110	26,249	(76)	26,174
6.	115	7,492	(20)	7,472
7.	125	7,436	0	7,436
8.	135	2,580	0	2,580
9.	145	12,452	(127)	12,324
10.	170	18,828	34	18,862
11.	200	32,841	0	32,841
12.	300	491	0	491
13.	SUB-TOTAL	2,445,618	6,678	2,452,296
14.	STORAGE	1,632	0	1,632
15.	DPAC	2,828	0	2,828
16.	TOTAL	2,450,078	6,678	2,456,756

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
Item No.	Rate No.		Rate Block m³	EB-2009-0309 cents *	Rate Change cents *	EB-2009-0172 cents *
	RATE 1					
1.01		Customer Charge		$16.00	$2.00	$18.00
1.02		Delivery Charge	first 30	8.6215	(0.5208)	8.1007
1.03			next 55	8.0661	(0.4873)	7.5789
1.04			next 85	7.6309	(0.4610)	7.1700
1.05			over 170	7.3069	(0.4414)	6.8655
1.06		Gas Supply Load Balancing		0.6569	0.0013	0.6582
1.07		Gas Supply Transportation		4.0236	(0.1141)	3.9094
1.08		Gas Supply Commodity - System		19.8615	(0.0496)	19.8119
1.09		Gas Supply Commodity - Buy/Sell		19.8438	(0.0543)	19.7895
	RATE 6					
2.01		Customer Charge		$55.00	$5.00	$60.00
2.02		Delivery Charge	First 500	7.3900	0.0731	7.4631
2.03			Next 1050	5.6493	0.0559	5.7051
2.04			Next 4500	4.4306	0.0438	4.4745
2.05			Next 7000	3.6474	0.0361	3.6834
2.06			Next 15250	3.2993	0.0326	3.3320
2.07			Over 28300	3.2122	0.0318	3.2440
2.08		Gas Supply Load Balancing		0.6253	(0.0056)	0.6197
2.09		Gas Supply Transportation		4.0236	(0.1141)	3.9094
2.10		Gas Supply Commodity - System		19.9793	(0.0819)	19.8974
2.11		Gas Supply Commodity - Buy/Sell		19.9616	(0.0866)	19.8750
	RATE 9					
3.01		Customer Charge		$232.64	$2.51	$235.15
3.02		Delivery Charge	first 20000	10.5211	0.2780	10.7991
3.03			over 20000	9.8480	0.2602	10.1082
3.04		Gas Supply Load Balancing		0.0013	0.0019	0.0032
3.05		Gas Supply Transportation		4.0236	(0.1141)	3.9094
3.06		Gas Supply Commodity - System		19.6846	(0.0114)	19.6732
3.07		Gas Supply Commodity - Buy/Sell		19.6668	(0.0160)	19.6508
	RATE 100					
4.01		Customer Charge		$121.23	$1.29	$122.52
4.02		Demand Charge (Cents/Month/m³)		8.1900	0.0000	8.1900
4.03		Delivery Charge	first 14,000	5.0695	0.1449	5.2144
4.04			next 28,000	3.7105	0.1449	3.8554
4.05			over 42,000	3.1515	0.1449	3.2964
4.06		Gas Supply Load Balancing		0.4252	(0.0056)	0.4768
4.07		Gas Supply Transportation		4.0236	(0.1141)	3.9094
4.08		Gas Supply Commodity - System		19.8176	(0.0819)	19.7364
		Gas Supply Commodity - Buy/Sell		19.7990	(0.0866)	19.7178
	RATE 110					
5.01		Customer Charge		$583.61	$6.19	$589.80
5.02		Demand Charge (Cents/Month/m³)		22.9100	0.0000	22.9100
5.03		Delivery Charge	first 1,000,000	0.5013	0.1543	0.6556
5.04			over 1,000,000	0.3513	0.1543	0.5056
5.05		Load Balancing Commodity		0.1178	0.0143	0.1321
5.06		Gas Supply Transportation		4.0236	(0.1141)	3.9094
5.07		Gas Supply Commodity - System		19.6846	(0.0114)	19.6732
5.08		Gas Supply Commodity - Buy/Sell		19.6668	(0.0160)	19.6508

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³		Col. 3 0.00 EB-2009-0309 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2009-0172 cents *
	RATE 115						
1.01		Customer Charge			$619.67	$6.27	$625.94
1.02		Demand Charge (Cents/Month/m³)			24.3600	0.0000	24.3600
1.03		Delivery Charge	first	1,000,000	0.2410	0.1337	0.3747
1.04			over	1,000,000	0.1410	0.1337	0.2747
1.05		Load Balancing Commodity			0.0307	0.0137	0.0444
1.06		Gas Supply Transportation			4.0236	(0.1141)	3.9094
1.07		Gas Supply Commodity - System			19.6846	(0.0114)	19.6732
1.08		Gas Supply Commodity - Buy/Sell			19.6668	(0.0160)	19.6508
	RATE 125						
2.01		Customer Charge			$ 500.00	$0.00	$ 500.00
2.02		Delivery Charge (Cents/Month/m³ of Contract Dmnd)			9.0093	0.0891	9.0984
	RATE 135	DEC - MAR					
3.00		Customer Charge			$114.54	$1.02	$115.56
3.01		Delivery Charge	first	14,000	6.6577	0.1517	6.8094
3.02			next	28,000	5.4577	0.1517	5.6094
3.03			over	42,000	5.0577	0.1517	5.2094
3.04		Gas Supply Load Balancing			0.0000	0.0000	0.0000
3.05		Gas Supply Transportation			4.0236	(0.1141)	3.9094
3.06		Gas Supply Commodity - System			19.7870	(0.0513)	19.7357
3.07		Gas Supply Commodity - Buy/Sell			19.7693	(0.0560)	19.7133
	RATE 135	APR - NOV					
3.08		Customer Charge			$114.54	$1.02	$115.56
3.09		Delivery Charge	first	14,000	1.9577	0.1517	2.1094
3.10			next	28,000	1.2577	0.1517	1.4094
3.11			over	42,000	1.0577	0.1517	1.2094
3.12		Gas Supply Load Balancing			0.0000	0.0000	0.0000
3.13		Gas Supply Transportation			4.0236	(0.1141)	3.9094
3.14		Gas Supply Commodity - System			19.7870	(0.0513)	19.7357
3.15		Gas Supply Commodity - Buy/Sell			19.7693	(0.0560)	19.7133
	RATE 145						
4.00		Customer Charge			$122.53	$1.29	$123.82
4.01		Demand Charge (Cents/Month/m³)			8.2300	0.000	8.2300
4.02		Delivery Charge	first	14,000	2.7948	0.1079	2.9027
4.03			next	28,000	1.4358	0.1079	1.5437
4.04			over	42,000	0.8768	0.1079	0.9847
4.05		Gas Supply Load Balancing			0.2995	0.0598	0.3593
4.06		Gas Supply Transportation			4.0236	(0.1141)	3.9094
4.07		Gas Supply Commodity - System			19.8689	(0.0168)	19.8521
4.08		Gas Supply Commodity - Buy/Sell			19.8511	(0.0214)	19.8297
	RATE 170						
5.00		Customer Charge			$277.09	$2.54	$279.63
5.01		Demand Charge (Cents/Month/m³)			4.0900	0.0000	4.0900
5.02		Delivery Charge	first	1,000,000	0.4648	0.1036	0.5683
5.03			over	1,000,000	0.2648	0.1036	0.3683
5.04		Gas Supply Load Balancing			0.1597	0.0417	0.2014
5.05		Gas Supply Transportation			4.0236	(0.1141)	3.9094
5.06		Gas Supply Commodity - System			19.6846	(0.0114)	19.6732
5.07		Gas Supply Commodity - Buy/Sell			19.6668	(0.0160)	19.6508

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2009-0309 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2009-0172 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		1.0606	0.1292	1.1899
1.03		Gas Supply Load Balancing		0.4866	0.0266	0.5132
1.04		Gas Supply Transportation		4.0236	(0.1141)	3.9094
1.05		Gas Supply Commodity - System		19.6846	(0.0114)	19.6732
1.06		Gas Supply Commodity - Buy/Sell		19.6668	(0.0160)	19.6508
	RATE 300	FIRM SERVICE				
2.00		Monthly Customer Charge		$500.00	$0.00	$500.00
2.01		Demand Charge (Cents/Month/m³)		24.7336	0.2448	24.9784
		INTERRUPTIBLE SERVICE				
2.02		Minimum Delivery Charge (Cents/Month/m³)		0.3554	0.0036	0.3590
2.03		Maximum Delivery Charge (Cents/Month/m³)		0.9758	0.0096	0.9854
	RATE 315					
		Monthly Customer Charge		$150.00	$0.00	$150.00
3.00		Space Demand Chg (Cents/Month/m³)		0.0466	0.0073	0.0539
3.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		13.5595	1.1687	14.7283
3.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.4637	(0.1264)	0.3373
	RATE 320					
4.00		Backstop	All Gas Sold	24.1326	0.0198	24.1524
	RATE 316					
		Monthly Customer Charge		$150.00	$0.00	$150.00
5.00		Space Demand Chg (Cents/Month/m³)		0.0466	0.0074	0.0539
5.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		4.3168	0.7531	5.0698
5.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.1173	0.0001	0.1174

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

		Col.1	Col. 2	Col. 3	Col. 4	Col. 5
				0.00		
Item No.	Rate No.		Rate Block m³	EB-2009-0309 cents *	Change cents *	EB-2009-0172 cents *
	RATE 325					
		Transmission & Compression				
1.00		Demand Charge - ATV ($/Month/10³ m³)		0.1838	0.0026	0.1865
1.01		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		16.6188	0.2387	16.8575
1.02		Commodity Charge		1.0680	0.0096	1.0776
		Storage				
1.03		Demand Charge - ATV ($/Month/10*3 m³)		0.2185	0.0027	0.2212
1.04		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		19.8179	0.2438	20.0617
1.05		Commodity Charge		0.3810	0.0015	0.3825
	RATE 330	Storage Service - Firm				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.00		Minimum		0.4023	0.0054	0.4077
2.01		Maximum		2.0115	0.0270	2.0385
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.02		Minimum		36.4368	0.4824	36.9192
2.03		Maximum		182.1839	2.4121	184.5960
		Commodity Charge				
2.04		Minimum		1.4490	0.0111	1.4601
2.05		Maximum		7.2450	$0.0555	7.3005
		Storage Service - Interruptible				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.06		Minimum		0.4023	0.0054	0.4077
2.07		Maximum		2.0115	0.0270	2.0385
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.08		Minimum		29.1494	0.3860	29.5354
2.09		Maximum		145.7471	$1.9297	147.6768
		Commodity Charge				
2.10		Minimum		1.4490	0.0111	1.4601
2.11		Maximum		7.2450	0.0555	7.3005
		Storage Service - Off Peak				
		Commodity Charge				
2.12		Minimum		0.7131	0.0098	0.7229
2.13		Maximum		38.4637	0.4689	38.9327
	RATE 331	Tecumseh Transmission Service				
		Firm				
		Demand Charge ($/Month/10³ m³ of				
3.00		Maximum Contracted Daily Delivery)		5.1620	0.0960	5.2580
		Interruptible				
3.01		Commodity Charge ($/10³m³ of gas delivered)		0.2040	0.0030	0.2070

NOTE : * Cents unless otherwise noted.

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	1,041,582	595,386	391,035	270	-	8,623	855	1,161	4,951	15,666	23,635	
1.2	Bad Debt Commodity	8,715	4,204	4,462	-	-	-	-	4	45	-	-	
1.3	System Gas Fee	1,187	679	446	0	-	10	1	1	6	18	27	
1.4	Return on Rate Base - Working Cash	266	152	100	0	-	2	0	0	1	4	6	
1	Total Commodity Costs	1,051,750	600,421	396,043	271	-	8,635	856	1,166	5,003	15,688	23,668	
	VOLUMES (10^3 m^3)												
2.1	System and Buy/Sell Volumes	5,301,806	3,030,604	1,990,425	1,375	-	43,892	4,350	5,908	25,201	79,744	120,305	
2.2	System Volumes	5,301,806	3,030,604	1,990,425	1,375	-	43,892	4,350	5,908	25,201	79,744	120,305	
	GAS SUPPLY CHARGE SYSTEM (¢/m^3)												
3.1	Annual Commodity	19.6458	19.6458	19.6458	19.6458	-	19.6458	19.6458	19.6458	19.6458	19.6458	19.6458	1.1 / 2.1
3.2	Bad Debt Commodity	0.1644	0.1387	0.2242	-	-	-	-	0.0625	0.1789	-	-	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	0.0050	0.0050	0.0050	0.0050	-	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	1.4 / 2.1
3	System Gas Supply Charge	19.8376	19.8119	19.8974	19.6732	-	19.6732	19.6732	19.7357	19.8521	19.6732	19.6732	
	GAS SUPPLY CHARGE BUY/SELL(¢/m3)												
4.1	Annual Commodity	19.6458	19.6458	19.6458	19.6458	-	19.6458	19.6458	19.6458	19.6458	19.6458	19.6458	1.1 / 2.1
4.2	Bad Debt Commodity	0.1644	0.1387	0.2242	-	-	-	-	0.0625	0.1789	-	-	1.2 / 2.1
4.3	Return on Rate Base - Working Cash	0.0050	0.0050	0.0050	0.0050	-	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	1.4 / 2.1
4	Buy/Sell Gas Supply Charge	19.8152	19.7895	19.8750	19.6508	-	19.6508	19.6508	19.7133	19.8297	19.6508	19.6508	

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	12,124	6,382	5,518	0	-	83	24	-	-	-	117	
5.2	Seasonal	12,906	6,300	5,720	-	-	172	43	-	208	285	178	
5.3	Return on Rate Base - Gas in Inventory	36,662	17,896	16,250	-	-	488	122	-	590	809	506	
5	Total Load Balancing	61,691	30,578	27,488	0	-	743	189	-	798	1,094	801	
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,051,101	4,646,080	4,435,727	1,693	-	562,719	425,510	58,120	222,012	543,100	156,140	
7	**ANNUAL LOAD BALANCING CHARGE (¢/m3)**		0.6582	0.6197	0.0032	-	0.1321	0.0444	-	0.3593	0.2014	0.5132	5.0 / 6
	DERIVATION OF TRANSPORTATION CHARGES												
8	Pipeline Annual incl. some M12 (upstrean	264,578	138,996	109,247	66	-	4,107	696	895	2,170	3,697	4,703	
	VOLUMES (10^3 m^3)												
9	Total Transportation Volumes	6,767,662	3,555,403	2,794,436	1,693	-	105,047	17,804	22,897	55,519	94,559	120,305	
10	**PROPOSED TRANSPORTATION CHARGE (¢/m^3)**		3.9094	3.9094	3.9094	3.9094	3.9094	3.9094	3.9094	3.9094	3.9094	3.9094	

CALCULATION OF SEASONAL CREDIT FOR RATE 135, 145, 170 & 200

RATE 135		
Seasonal Credits Applicable to Rate 135	**$**	**(490)**
Annual Volume (103 m3)		58,120
Mean Daily Volume (103 m3)		159
Annual Seasonal Credits	$	(3.08)
Payable from December to March	$	(0.77)
RATE 145		
Seasonal Credits Applicable to Rate 145	**$**	**(791)**
Annual Volume (103 m3)		222,012
Mean Daily Volume (103 m3)		
16 Hours		332
72 Hours		282
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	$	(663.71)
72 Hours	$	(126.87)
RATE 170		
Seasonal Credits Applicable to Rate 170	**$**	**(6,547)**
Annual Volume (103 m3)		543,100
Mean Daily Volume (103 m3)		1,488
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)
RATE 200		
Seasonal Credits Applicable to Rate 200	**$**	**(95)**
Annual Volume (103 m3)		7,917
Mean Daily Volume (103 m3)		22
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)

DETAILED REVENUE CALCULATION

		Col. 1		Col. 2	Col. 3	Col. 4
				EB-2009-0172		
Item No.		Rate Block m³		Bills & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 1					
1.1	Customer Charge	Bills		21,272,386	$18.00	382,903
1.2	Delivery Charge	first	30	609,167	8.1007	49,347
1.3		next	55	895,724	7.5789	67,886
1.4		next	85	980,304	7.1700	70,287
1.5		over	170	2,160,885	6.8655	148,356
1.	Total Distribution Charge			4,646,080		718,778
2.1	Gas Supply Load Balancing			4,646,080	0.6582	30,578
2.2	Gas Supply Transportation			3,555,403	3.9094	138,996
3.1	Gas Supply Commodity - System			3,030,604	19.8119	600,420
3.2	Gas Supply Commodity - Buy/Sell			0	19.7895	0
3.	Total Gas Supply Charge			3,030,604		600,420
4.1	TOTAL DISTRIBUTION			4,646,080		718,778
4.2	TOTAL GAS SUPPLY LOAD BALANCING			4,646,080		169,575
4.3	TOTAL GAS SUPPLY COMMODITY			3,030,604		600,420
4.	TOTAL RATE 1			**4,646,080**		1,488,773
5.	Adj. Factor	0.9999				
6.	ADJUSTED REVENUE					**1,488,686**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2009-0172		
Item No.		Rate Block m³	Bills & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 6				
1.1	Customer Charge	Bills	1,899,096	$60.00	113,946
1.2	Delivery Charge	First 500	553,892	7.4631	41,338
1.3		Next 1050	650,958	5.7051	37,138
1.4		Next 4500	1,165,170	4.4745	52,135
1.5		Next 7000	712,638	3.6834	26,250
1.6		Next 15250	614,293	3.3320	20,468
1.7		Over 28300	738,776	3.2440	23,966
1.	Total Distribution Charge		4,435,727		315,240
2.1	Gas Supply Load Balancing		4,435,727	0.6197	27,488
2.2	Gas Supply Transportation		2,794,436	3.9094	109,247
3.1	Gas Supply Commodity - System		1,990,425	19.8974	396,043
3.2	Gas Supply Commodity - Buy/Sell		0	19.8750	0
3.	Total Gas Supply Charge		1,990,425		396,043
4.1	TOTAL DISTRIBUTION		4,435,727		315,240
4.2	TOTAL GAS SUPPLY LOAD BALANCING		4,435,727		136,735
4.3	TOTAL GAS SUPPLY COMMODITY		1,990,425		396,043
4.	TOTAL RATE 6		**4,435,727**		848,018
5.	Adj. Factor	1.000			
6.	ADJUSTED REVENUE				**847,968**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2009-0172		
Item No.		Rate Block m³	Bills & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 9				
1.1	Customer Charge	Bills	324	$235.15	76
1.2	Delivery Charge	first 20000	1,655	10.7991	179
1.3		over 20000	38	10.1082	4
1.	Total Distribution Charge		1,693		259
2.1	Gas Supply Load Balancing		1,693	0.0032	0
2.2	Gas Supply Transportation		1,693	3.9094	66
3.1	Gas Supply Commodity - System		1,375	19.6732	271
3.2	Gas Supply Commodity - Buy/Sell		0	19.6508	0
3.	Total Gas Supply Charge		1,375		271
4.1	TOTAL DISTRIBUTION		1,693		259
4.2	TOTAL GAS SUPPLY LOAD BALANCING		1,693		66
4.3	TOTAL GAS SUPPLY COMMODITY		1,375		271
4	TOTAL RATE 9		**1,693**		**596**

			EB-2009-0172		
		Rate Block m³	Contracts & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 100				
1.1	Customer Charge	Contracts	0	$122.52	0
1.2	Demand Charge		0	8.19	0
1.3	Delivery Charge	first 14,000	0	5.2144	0
1.4		next 28,000	0	3.8554	0
1.5		over 42,000	0	3.2964	0
1	Total Distribution Charge		0		0
2.1	Gas Supply Load Balancing		0	0.4768	0
2.2	Gas Supply Transportation		0	3.9094	0
3.1	Gas Supply Commodity - System		0	19.7364	0
3.2	Gas Supply Commodity - Buy/Sell		0	19.7178	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.

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2009-0172 Contracts & Volumes 10^3 m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 110				
1.1	Customer Charge	Contracts	2,784	$589.80	1,642
1.2	Demand Charge		32,954	22.9100	7,550
1.3	Delivery Charge	first 1,000,000	484,993	0.6556	3,179
1.4		over 1,000,000	77,726	0.5056	393
1.	Total Distribution Charge		562,719		12,764
2.1	Load Balancing Commodity		562,719	0.1321	743
2.2	Gas Supply Transportation		105,047	3.9094	4,107
2.	Total Gas Supply Load Balancing				4,850
3.1	Gas Supply Commodity - System		43,892	19.6732	8,635
3.2	Gas Supply Commodity - Buy/Sell		0	19.6508	0
3.	Total Gas Supply Charge		43,892		8,635
4.1	TOTAL DISTRIBUTION		562,719		12,764
4.2	TOTAL GAS SUPPLY LOAD BALANCING		562,719		4,850
4.3	TOTAL GAS SUPPLY COMMODITY		43,892		8,635
4.	TOTAL RATE 110		**562,719**		**26,250**

		Rate Block m³	EB-2009-0172 Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 115				
6.6	Customer Charge	Contracts	432	$625.94	270
6.2	Demand Charge		16,957	24.3600	4,131
6.3	Delivery Charge	first 1,000,000	181,386	0.3747	680
6.4		over 1,000,000	244,123	0.2747	671
6	Total Distribution Charge		425,510		5,751
7.1	Load Balancing Commodity		425,510	0.0444	189
7.2	Gas Supply Transportation		17,804	3.9094	696
7	Total Gas Supply Load Balancing				885
8.1	Gas Supply Commodity - System		4,350	19.6732	856
8.2	Gas Supply Commodity - Buy/Sell		0	19.6508	0
8.	Total Gas Supply Charge		4,350		856
9.1	TOTAL DISTRIBUTION		425,510		5,751
9.2	TOTAL GAS SUPPLY LOAD BALANCING		425,510		885
9.3	TOTAL GAS SUPPLY COMMODITY		4,350		856
9.	TOTAL RATE 115		**425,510**		**7,492**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2009-0172 Contracts & Volumes 10³ m³	Col. 3 EB-2009-0172 Rate cents*	Col. 4 EB-2009-0172 Revenues $000
	RATE 125				
1.1	Customer Charge		48	$ 500.00	24
1.2	Demand Charge		81,462	9.0984	7,412
1.	Total Distribution Charge		81,462		7,436

Item No.		Rate Block m³	EB-2009-0172 Contracts & Volumes 10³ m³	EB-2009-0172 Rate cents*	EB-2009-0172 Revenues $000
	RATE 135				
	DEC to MAR				
1.1	Customer Charge	Contracts	160	$115.56	18
1.2	Delivery Charge	first 14,000	651	6.8094	44
1.3		next 28,000	1,047	5.6094	59
1.4		over 42,000	2,847	5.2094	148
1.	Total Distribution Charge		4,545		270
2.1	Gas Supply Load Balancing		4,545	0.0000	0
2.2	Gas Supply Transportation		1,873	3.9094	73
2.3	Seasonal Credit				(490)
3.1	Gas Supply Commodity - System		228	19.7357	45
3.2	Gas Supply Commodity - Buy/Sell		0	19.7133	0
3.	Total Gas Supply Charge		228		45
4.	SUB-TOTAL WINTER				-102
	APR to NOV				
5.1	Customer Charge	Contracts	320	$115.56	37
5.2	Delivery Charge	first 14,000	4,214	2.1094	89
5.3		next 28,000	8,121	1.4094	114
5.4		over 42,000	41,239	1.2094	499
5.	Total Distribution Charge		53,575		739
6.1	Gas Supply Load Balancing		53,575	0.0000	0
6.2	Gas Supply Transportation		21,024	3.9094	822
7.1	Gas Supply Commodity - System		5,681	19.7357	1,121
7.2	Gas Supply Commodity - Buy/Sell		0	19.7133	0
7.	Total Gas Supply Charge		5,681		1,121
8.	SUB-TOTAL SUMMER				2,682
9.1	TOTAL DISTRIBUTION		58,120		1,009
9.2	TOTAL GAS SUPPLY LOAD BALANCING		58,120		405
9.3	TOTAL GAS SUPPLY COMMODITY		5,908		1,166
9.	TOTAL RATE 135		**58,120**		**2,580**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2009-0172 Contracts & Volumes 10³ m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 145				
1.1	Customer Charge	Contracts	2,300	$123.82	285
1.2	Demand Charge		23,443	8.2300	1,929
1.2	Delivery Charge	first 14,000	30,506	2.9027	886
1.3		next 28,000	51,121	1.5437	789
1.4		over 42,000	140,384	0.9847	1,382
1.	Total Distribution Charge		222,012		5,271
2.1	Gas Supply Load Balancing		222,012	0.3593	798
2.2	Gas Supply Transportation		55,519	3.9094	2,170
2.3	Curtailment Credit				(791)
3.1	Gas Supply Commodity - System		25,201	19.8521	5,003
3.2	Gas Supply Commodity - Buy/Sell		0	19.8297	0
3.	Total Gas Supply Charge		25,201		5,003
4.1	TOTAL DISTRIBUTION		222,012		5,271
4.2	TOTAL GAS SUPPLY LOAD BALANCING		222,012		2,178
4.3	TOTAL GAS SUPPLY COMMODITY		25,201		5,003
4.	TOTAL RATE 145		**222,012**		**12,452**

		Rate Block m³	EB-2009-0172 Contracts & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 170				
6.6	Customer Charge	Contracts	468	$279.63	131
6.2	Demand Charge		51,358	4.0900	2,101
6.3	Delivery Charge	first 1,000,000	332,130	0.5683	1,888
6.4		over 1,000,000	210,970	0.3683	777
6	Total Distribution Charge		543,100		4,896
7.1	Gas Supply Load Balancing		543,100	0.2014	1,094
7.7	Gas Supply Transportation		94,559	3.9094	3,697
7.3	Curtailment Credit				(6,547)
8.1	Gas Supply Commodity - System		79,744	19.6732	15,688
8.2	Gas Supply Commodity - Buy/Sell		0	19.6508	0
8.	Total Gas Supply Charge		79,744		15,688
9.1	TOTAL DISTRIBUTION		543,100		4,896
9.2	TOTAL GAS SUPPLY LOAD BALANCING		543,100		-1,756
9.3	TOTAL GAS SUPPLY COMMODITY		79,744		15,688
9.	TOTAL RATE 170		**543,100**		**18,827**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2009-0172		
Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 200				
1.1	Customer Charge	Contracts	12	$0.00	0
1.2	Demand Charge		13,237	14.7000	1,946
1.3	Delivery Charge		156,140	1.1899	1,858
1.	Total Distribution Charge		156,140		3,804
2.1	Gas Supply Load Balancing		156,140	0.5132	801
2.2	Gas Supply Transportation		120,305	3.9094	4,703
2.3	Curtailment Credit				(135)
3.1	Gas Supply Commodity - System		120,305	19.6732	23,668
3.2	Gas Supply Commodity - Buy/Sell		0	19.6508	0
3.	Total Gas Supply Charge		120,305		23,668
4.1	TOTAL DISTRIBUTION		156,140		3,804
4.2	TOTAL GAS SUPPLY LOAD BALANCING		156,140		5,369
4.3	TOTAL GAS SUPPLY COMMODITY		120,305		23,668
4.	TOTAL RATE 200		**156,140**		**32,841**

			EB-2009-0172		
		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 300				
	Firm				
	Customer Charge		120	$500.00	60
	Demand Charge		1,137	24.9784	284
	Interruptible				
	Minimum Delivery Charge		41,030	0.3590	147
	Maximum Delivery Charge		0	0.9854	0
8.	TOTAL RATE 300		**0**		**491**

NOTE: * Cents unless otherwise noted.

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2009-0172 @ 37.69 MJ/m³ vs (B) EB-2009-0309 @ 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.	$	216.00	192.00	24.00	12.5%	216.00	192.00	24.00	12.5%
1.3	DISTRIBUTION CHG.	$	221.33	235.56	(14.23)	-6.0%	333.64	355.11	(21.47)	-6.0%
1.4	LOAD BALANCING	§ $	139.96	143.42	(3.46)	-2.4%	214.27	219.54	(5.27)	-2.4%
1.5	SALES COMMDTY	$	607.05	608.55	(1.50)	-0.2%	929.39	931.69	(2.30)	-0.2%
1.6	TOTAL SALES	$	1,184.34	1,179.53	4.81	0.4%	1,693.30	1,698.34	(5.04)	-0.3%
1.7	TOTAL T-SERVICE	$	577.29	570.98	6.31	1.1%	763.91	766.65	(2.74)	-0.4%
1.8	SALES UNIT RATE	$/m³	0.3865	0.3850	0.0016	0.4%	0.3610	0.3620	(0.0011)	-0.3%
1.9	T-SERVICE UNIT RATE	$/m³	0.1884	0.1864	0.0021	1.1%	0.1628	0.1634	(0.0006)	-0.4%
1.10	SALES UNIT RATE	$/GJ	10.256	10.214	0.0417	0.4%	9.577	9.606	(0.0285)	-0.3%
1.11	T-SERVICE UNIT RATE	$/GJ	4.999	4.944	0.0546	1.1%	4.321	4.336	(0.0155)	-0.4%

			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.	$	216.00	192.00	24.00	12.5%	216.00	192.00	24.00	12.5%
2.3	DISTRIBUTION CHG.	$	141.95	151.09	(9.14)	-6.0%	147.74	157.22	(9.48)	-6.0%
2.4	LOAD BALANCING	§ $	89.30	91.51	(2.21)	-2.4%	91.57	93.85	(2.28)	-2.4%
2.5	SALES COMMDTY	$	387.32	388.28	(0.96)	-0.2%	397.23	398.24	(1.01)	-0.3%
2.6	TOTAL SALES	$	834.57	822.88	11.69	1.4%	852.54	841.31	11.23	1.3%
2.7	TOTAL T-SERVICE	$	447.25	434.60	12.65	2.9%	455.31	443.07	12.24	2.8%
2.8	SALES UNIT RATE	$/m³	0.4269	0.4209	0.0060	1.4%	0.4252	0.4196	0.0056	1.3%
2.9	T-SERVICE UNIT RATE	$/m³	0.2288	0.2223	0.0065	2.9%	0.2271	0.2210	0.0061	2.8%
2.10	SALES UNIT RATE	$/GJ	11.326	11.168	0.1587	1.4%	11.282	11.133	0.1486	1.3%
2.11	T-SERVICE UNIT RATE	$/GJ	6.070	5.898	0.1717	2.9%	6.025	5.863	0.1620	2.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2009-0172 @ 37.69 MJ/m³ vs (B) EB-2009-0309 @ 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)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	216.00	192.00	24.00	12.5%	216.00	192.00	24.00	12.5%
3.3	DISTRIBUTION CHG.	$	358.80	381.91	(23.11)	-6.1%	83.42	88.72	(5.30)	-6.0%
3.4	LOAD BALANCING	§ $	230.58	236.26	(5.68)	-2.4%	49.37	50.60	(1.23)	-2.4%
3.5	SALES COMMDTY	$	1,000.10	1,002.61	(2.51)	-0.3%	214.17	214.71	(0.54)	-0.3%
3.6	TOTAL SALES	$	1,805.48	1,812.78	(7.30)	-0.4%	562.96	546.03	16.93	3.1%
3.7	TOTAL T-SERVICE	$	805.38	810.17	(4.79)	-0.6%	348.79	331.32	17.47	5.3%
3.8	SALES UNIT RATE	$/m³	0.3577	0.3591	(0.0014)	-0.4%	0.5208	0.5051	0.0157	3.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1595	0.1605	(0.0009)	-0.6%	0.3227	0.3065	0.0162	5.3%
3.10	SALES UNIT RATE	$/GJ	9.490	9.528	(0.0384)	-0.4%	13.817	13.402	0.4155	3.1%
3.11	T-SERVICE UNIT RATE	$/GJ	4.233	4.258	(0.0252)	-0.6%	8.561	8.132	0.4288	5.3%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2009-0172 @ 37.69 MJ/m³ vs (B) EB-2009-0309 @ 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.	$	720.00	660.00	60.00	9.1%	720.00	660.00	60.00	9.1%
1.3	DISTRIBUTION CHG.	$	1,276.81	1,264.30	12.51	1.0%	1,638.20	1,622.17	16.03	1.0%
1.4	LOAD BALANCING	§ $	1,023.86	1,050.92	(27.06)	-2.6%	1,326.03	1,361.09	(35.06)	-2.6%
1.5	SALES COMMDTY	$	4,498.01	4,516.52	(18.51)	-0.4%	5,825.57	5,849.53	(23.96)	-0.4%
1.6	TOTAL SALES	$	7,518.68	7,491.74	26.94	0.4%	9,509.80	9,492.79	17.01	0.2%
1.7	TOTAL T-SERVICE	$	3,020.67	2,975.22	45.45	1.5%	3,684.23	3,643.26	40.97	1.1%
1.8	SALES UNIT RATE	$/m³	0.3326	0.3314	0.0012	0.4%	0.3248	0.3242	0.0006	0.2%
1.9	T-SERVICE UNIT RATE	$/m³	0.1336	0.1316	0.0020	1.5%	0.1258	0.1244	0.0014	1.1%
1.10	SALES UNIT RATE	$/GJ	8.825	8.793	0.0316	0.4%	8.618	8.603	0.0154	0.2%
1.11	T-SERVICE UNIT RATE	$/GJ	3.545	3.492	0.0533	1.5%	3.339	3.302	0.0371	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.	$	720.00	660.00	60.00	9.1%	720.00	660.00	60.00	9.1%
2.3	DISTRIBUTION CHG.	$	6,875.72	6,808.46	67.26	1.0%	12,589.14	12,465.94	123.20	1.0%
2.4	LOAD BALANCING	§ $	7,679.73	7,882.72	(202.99)	-2.6%	15,359.43	15,765.42	(405.99)	-2.6%
2.5	SALES COMMDTY	$	33,738.60	33,877.51	(138.91)	-0.4%	67,477.05	67,754.81	(277.76)	-0.4%
2.6	TOTAL SALES	$	49,014.05	49,228.69	(214.64)	-0.4%	96,145.62	96,646.17	(500.55)	-0.5%
2.7	TOTAL T-SERVICE	$	15,275.45	15,351.18	(75.73)	-0.5%	28,668.57	28,891.36	(222.79)	-0.8%
2.8	SALES UNIT RATE	$/m³	0.2891	0.2903	(0.0013)	-0.4%	0.2835	0.2850	(0.0015)	-0.5%
2.9	T-SERVICE UNIT RATE	$/m³	0.0901	0.0905	(0.0004)	-0.5%	0.0845	0.0852	(0.0007)	-0.8%
2.10	SALES UNIT RATE	$/GJ	7.669	7.703	(0.0336)	-0.4%	7.522	7.561	(0.0392)	-0.5%
2.11	T-SERVICE UNIT RATE	$/GJ	2.390	2.402	(0.0118)	-0.5%	2.243	2.260	(0.0174)	-0.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2009-0172 @ 37.69 MJ/m³ vs (B) EB-2009-0309 @ 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.	$	720.00	660.00	60.00	9.1%	720.00	660.00	60.00	9.1%
3.3	DISTRIBUTION CHG.	$	2,263.57	2,241.43	22.14	1.0%	3,035.89	3,006.19	29.70	1.0%
3.4	LOAD BALANCING	§ $	1,960.43	2,012.25	(51.82)	-2.6%	2,894.26	2,970.76	(76.50)	-2.6%
3.5	SALES COMMDTY	$	8,612.60	8,648.05	(35.45)	-0.4%	12,715.03	12,767.36	(52.33)	-0.4%
3.6	TOTAL SALES	$	13,556.60	13,561.73	(5.13)	0.0%	19,365.18	19,404.31	(39.13)	-0.2%
3.7	TOTAL T-SERVICE	$	4,944.00	4,913.68	30.32	0.6%	6,650.15	6,636.95	13.20	0.2%
3.8	SALES UNIT RATE	$/m³	0.3132	0.3133	(0.0001)	0.0%	0.3030	0.3037	(0.0006)	-0.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.1142	0.1135	0.0007	0.6%	0.1041	0.1039	0.0002	0.2%
3.10	SALES UNIT RATE	$/GJ	8.310	8.313	(0.0031)	0.0%	8.040	8.057	(0.0162)	-0.2%
3.11	T-SERVICE UNIT RATE	$/GJ	3.031	3.012	0.0186	0.6%	2.761	2.756	0.0055	0.2%

Item No.			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.	$	720.00	660.00	60.00	9.1%	720.00	660.00	60.00	9.1%
4.3	DISTRIBUTION CHG.	$	7,041.09	6,972.22	68.87	1.0%	12,712.04	12,587.61	124.43	1.0%
4.4	LOAD BALANCING	§ $	7,679.74	7,882.72	(202.98)	-2.6%	15,359.38	15,765.37	(405.99)	-2.6%
4.5	SALES COMMDTY	$	33,738.62	33,877.49	(138.87)	-0.4%	67,476.85	67,754.60	(277.75)	-0.4%
4.6	TOTAL SALES	$	49,179.45	49,392.43	(212.98)	-0.4%	96,268.27	96,767.58	(499.31)	-0.5%
4.7	TOTAL T-SERVICE	$	15,440.83	15,514.94	(74.11)	-0.5%	28,791.42	29,012.98	(221.56)	-0.8%
4.8	SALES UNIT RATE	$/m³	0.2900	0.2913	(0.0013)	-0.4%	0.2839	0.2853	(0.0015)	-0.5%
4.9	T-SERVICE UNIT RATE	$/m³	0.0911	0.0915	(0.0004)	-0.5%	0.0849	0.0856	(0.0007)	-0.8%
4.10	SALES UNIT RATE	$/GJ	7.695	7.729	(0.0333)	-0.4%	7.532	7.571	(0.0391)	-0.5%
4.11	T-SERVICE UNIT RATE	$/GJ	2.416	2.428	(0.0116)	-0.5%	2.253	2.270	(0.0173)	-0.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2009-0172 @ 37.69 MJ/m³ vs (B) EB-2009-0309 @ 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)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
1.2	CUSTOMER CHG.	$	1,470.24	1,454.76	15.48	1.1%	1,470.24	1,454.76	15.48	1.1%
1.3	DISTRIBUTION CHG.	$	17,938.92	17,447.41	491.51	2.8%	28,599.48	27,732.15	867.33	3.1%
1.4	LOAD BALANCING	$	14,877.58	15,089.73	(212.15)	-1.4%	26,254.61	26,628.98	(374.37)	-1.4%
1.5	SALES COMMDTY	$	66,943.38	67,218.94	(275.56)	-0.4%	118,135.59	118,621.83	(486.24)	-0.4%
1.6	TOTAL SALES	$	101,230.12	101,210.84	19.28	0.0%	174,459.92	174,437.72	22.20	0.0%
1.7	TOTAL T-SERVICE	$	34,286.74	33,991.90	294.84	0.9%	56,324.33	55,815.89	508.44	0.9%
1.8	SALES UNIT RATE	$/m³	0.2984	0.2984	0.0001	0.0%	0.2915	0.2914	0.0000	0.0%
1.9	T-SERVICE UNIT RATE	$/m³	0.1011	0.1002	0.0009	0.9%	0.0941	0.0932	0.0008	0.9%
1.10	SALES UNIT RATE	$/GJ	7.919	7.917	0.0015	0.0%	7.733	7.732	0.0010	0.0%
1.11	T-SERVICE UNIT RATE	$/GJ	2.682	2.659	0.0231	0.9%	2.497	2.474	0.0225	0.9%

			Rate 100 - Small Industrial Firm				**Rate 100 - Average Industrial Firm**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
2.2	CUSTOMER CHG.	$	1,470.24	1,454.76	15.48	1.1%	1,470.24	1,454.76	15.48	1.1%
2.3	DISTRIBUTION CHG.	$	18,211.70	17,720.21	491.49	2.8%	28,840.92	27,973.59	867.33	3.1%
2.4	LOAD BALANCING	$	14,877.59	15,089.73	(212.14)	-1.4%	26,254.55	26,628.94	(374.39)	-1.4%
2.5	SALES COMMDTY	$	66,943.37	67,218.96	(275.59)	-0.4%	118,135.39	118,621.64	(486.25)	-0.4%
2.6	TOTAL SALES	$	101,502.90	101,483.66	19.24	0.0%	174,701.10	174,678.93	22.17	0.0%
2.7	TOTAL T-SERVICE	$	34,559.53	34,264.70	294.83	0.9%	56,565.71	56,057.29	508.42	0.9%
2.8	SALES UNIT RATE	$/m³	0.2993	0.2992	0.0001	0.0%	0.2919	0.2918	0.0000	0.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.1019	0.1010	0.0009	0.9%	0.0945	0.0937	0.0008	0.9%
2.10	SALES UNIT RATE	$/GJ	7.940	7.938	0.0015	0.0%	7.744	7.743	0.0010	0.0%
2.11	T-SERVICE UNIT RATE	$/GJ	2.703	2.680	0.0231	0.9%	2.507	2.485	0.0225	0.9%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2009-0172 @ 37.69 MJ/m³ vs (B) EB-2009-0309 @ 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)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,485.84	1,470.36	15.48	1.1%	1,485.84	1,470.36	15.48	1.1%
3.3	DISTRIBUTION CHG.	$	10,112.08	9,746.11	365.97	3.8%	14,783.69	14,137.90	645.79	4.6%
3.4	LOAD BALANCING	$	12,619.32	12,803.41	(184.09)	-1.4%	22,269.82	22,594.67	(324.85)	-1.4%
3.5	SALES COMMDTY	$	67,335.95	67,392.92	(56.97)	-0.1%	118,828.32	118,928.86	(100.54)	-0.1%
3.6	TOTAL SALES	$	91,553.19	91,412.80	140.39	0.2%	157,367.67	157,131.79	235.88	0.2%
3.7	TOTAL T-SERVICE	$	24,217.24	24,019.88	197.36	0.8%	38,539.35	38,202.93	336.42	0.9%
3.8	SALES UNIT RATE	$/m³	0.2699	0.2695	0.0004	0.2%	0.2629	0.2625	0.0004	0.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.0714	0.0708	0.0006	0.8%	0.0644	0.0638	0.0006	0.9%
3.10	SALES UNIT RATE	$/GJ	7.162	7.151	0.0110	0.2%	6.976	6.965	0.0105	0.2%
3.11	T-SERVICE UNIT RATE	$/GJ	1.894	1.879	0.0154	0.8%	1.708	1.693	0.0149	0.9%

			Rate 145 - Small Industrial Interr.				**Rate 145 - Average Industrial Interr.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,485.84	1,470.36	15.48	1.1%	1,485.84	1,470.36	15.48	1.1%
4.3	DISTRIBUTION CHG.	$	10,384.88	10,018.90	365.98	3.7%	15,025.13	14,379.38	645.75	4.5%
4.4	LOAD BALANCING	$	12,619.32	12,803.42	(184.10)	-1.4%	22,269.79	22,594.64	(324.85)	-1.4%
4.5	SALES COMMDTY	$	67,335.94	67,392.91	(56.97)	-0.1%	118,828.10	118,928.68	(100.58)	-0.1%
4.6	TOTAL SALES	$	91,825.98	91,685.59	140.39	0.2%	157,608.86	157,373.06	235.80	0.1%
4.7	TOTAL T-SERVICE	$	24,490.04	24,292.68	197.36	0.8%	38,780.76	38,444.38	336.38	0.9%
4.8	SALES UNIT RATE	$/m³	0.2707	0.2703	0.0004	0.2%	0.2633	0.2629	0.0004	0.1%
4.9	T-SERVICE UNIT RATE	$/m³	0.0722	0.0716	0.0006	0.8%	0.0648	0.0642	0.0006	0.9%
4.10	SALES UNIT RATE	$/GJ	7.183	7.172	0.0110	0.2%	6.986	6.976	0.0105	0.1%
4.11	T-SERVICE UNIT RATE	$/GJ	1.916	1.900	0.0154	0.8%	1.719	1.704	0.0149	0.9%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2009-0172 @ 37.69 MJ/m³ vs (B) EB-2009-0309 @ 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)	%	(A)	(B)	CHANGE (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.	$	7,077.60	7,003.32	74.28	1.1%	7,077.60	7,003.32	74.28	1.1%
5.3	DISTRIBUTION CHG.	$	12,974.42	12,050.85	923.57	7.7%	212,464.81	197,071.87	15,392.94	7.8%
5.4	LOAD BALANCING	$	24,191.30	24,788.83	(597.53)	-2.4%	403,187.67	413,146.61	(9,958.94)	-2.4%
5.5	SALES COMMDTY	$	117,757.49	117,825.73	(68.24)	-0.1%	1,962,622.22	1,963,759.50	(1,137.28)	-0.1%
5.6	TOTAL SALES	$	162,000.81	161,668.73	332.08	0.2%	2,585,352.30	2,580,981.30	4,371.00	0.2%
5.7	TOTAL T-SERVICE	$	44,243.32	43,843.00	400.32	0.9%	622,730.08	617,221.80	5,508.28	0.9%
5.8	SALES UNIT RATE	$/m³	0.2706	0.2701	0.0006	0.2%	0.2592	0.2587	0.0004	0.2%
5.9	T-SERVICE UNIT RATE	$/m³	0.0739	0.0732	0.0007	0.9%	0.0624	0.0619	0.0006	0.9%
5.10	SALES UNIT RATE	$/GJ	7.181	7.166	0.0147	0.2%	6.876	6.864	0.0116	0.2%
5.11	T-SERVICE UNIT RATE	$/GJ	1.961	1.943	0.0177	0.9%	1.656	1.642	0.0146	0.9%

			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (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.	$	7,077.60	7,003.32	74.28	1.1%	7,511.28	7,436.04	75.24	1.0%
6.3	DISTRIBUTION CHG.	$	165,506.92	150,113.99	15,392.93	10.3%	902,245.85	808,875.17	93,370.68	11.5%
6.4	LOAD BALANCING	$	403,187.64	413,146.57	(9,958.93)	-2.4%	2,761,061.38	2,831,201.92	(70,140.54)	-2.5%
6.5	SALES COMMDTY	$	1,962,622.04	1,963,759.31	(1,137.27)	-0.1%	13,738,356.25	13,746,317.18	(7,960.93)	-0.1%
6.6	TOTAL SALES	$	2,538,394.20	2,534,023.19	4,371.01	0.2%	17,409,174.76	17,393,830.31	15,344.45	0.1%
6.7	TOTAL T-SERVICE	$	575,772.16	570,263.88	5,508.28	1.0%	3,670,818.51	3,647,513.13	23,305.38	0.6%
6.8	SALES UNIT RATE	$/m³	0.2544	0.2540	0.0004	0.2%	0.2493	0.2491	0.0002	0.1%
6.9	T-SERVICE UNIT RATE	$/m³	0.0577	0.0572	0.0006	1.0%	0.0526	0.0522	0.0003	0.6%
6.10	SALES UNIT RATE	$/GJ	6.751	6.739	0.0116	0.2%	6.614	6.609	0.0058	0.1%
6.11	T-SERVICE UNIT RATE	$/GJ	1.531	1.517	0.0146	1.0%	1.395	1.386	0.0089	0.6%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2009-0172 @ 37.69 MJ/m³ vs (B) EB-2009-0309 @ 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.	$	1,386.72	1,374.48	12.24	0.9%	3,355.56	3,325.08	30.48	0.9%
7.3	DISTRIBUTION CHG.	$	8,663.4	7,755.69	907.73	11.7%	81,752.9	71,422.20	10,330.69	14.5%
7.4	LOAD BALANCING	$	18,355.12	19,038.17	(683.05)	-3.6%	289,844.75	297,066.52	(7,221.77)	-2.4%
7.5	SALES COMMDTY	$	118,131.39	118,438.45	(307.06)	-0.3%	1,962,622.22	1,963,759.50	(1,137.28)	-0.1%
7.6	TOTAL SALES	$	146,536.65	146,606.79	(70.14)	0.0%	2,337,575.42	2,335,573.30	2,002.12	0.1%
7.7	TOTAL T-SERVICE	$	28,405.26	28,168.34	236.92	0.8%	374,953.20	371,813.80	3,139.40	0.8%
7.8	SALES UNIT RATE	$/m³	0.2448	0.2449	(0.0001)	0.0%	0.2343	0.2341	0.0002	0.1%
7.9	T-SERVICE UNIT RATE	$/m³	0.0475	0.0471	0.0004	0.8%	0.0376	0.0373	0.0003	0.8%
7.10	SALES UNIT RATE	$/GJ	6.495	6.499	(0.0031)	0.0%	6.217	6.212	0.0053	0.1%
7.11	T-SERVICE UNIT RATE	$/GJ	1.259	1.249	0.0105	0.8%	0.997	0.989	0.0083	0.8%

			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.	$	3,355.56	3,325.08	30.48	0.9%	3,355.56	3,325.08	30.48	0.9%
8.3	DISTRIBUTION CHG.	$	74,568.1	64,237.34	10,330.71	16.1%	406,408.1	334,093.14	72,315.00	21.6%
8.4	LOAD BALANCING	$	289,844.72	297,066.47	(7,221.75)	-2.4%	2,028,913.37	2,079,465.64	(50,552.27)	-2.4%
8.5	SALES COMMDTY	$	1,962,622.04	1,963,759.31	(1,137.27)	-0.1%	13,738,356.25	13,746,317.18	(7,960.93)	-0.1%
8.6	TOTAL SALES	$	2,330,390.37	2,328,388.20	2,002.17	0.1%	16,177,033.32	16,163,201.04	13,832.28	0.1%
8.7	TOTAL T-SERVICE	$	367,768.33	364,628.89	3,139.44	0.9%	2,438,677.07	2,416,883.86	21,793.21	0.9%
8.8	SALES UNIT RATE	$/m³	0.2336	0.2334	0.0002	0.1%	0.2317	0.2315	0.0002	0.1%
8.9	T-SERVICE UNIT RATE	$/m³	0.0369	0.0366	0.0003	0.9%	0.0349	0.0346	0.0003	0.9%
8.10	SALES UNIT RATE	$/GJ	6.198	6.193	0.0053	0.1%	6.146	6.141	0.0053	0.1%
8.11	T-SERVICE UNIT RATE	$/GJ	0.978	0.970	0.0083	0.9%	0.927	0.918	0.0083	0.9%

Measure of 2010 Revenues vs 2010 Revenue Requirement
December 31, 2010
(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
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	RATE 325 & 330	DIRECT PURCHASE
1.	Sales and Delivery Revenue	2,450.08	1,488.69	847.97	0.60	0.00	26.25	7.49	7.44	2.58	12.45	18.83	32.84	0.49	1.63	2.83
2.	Unbilled Revenues	6.68	2.49	4.38	0.00	0.00	(0.08)	(0.02)	0.00	0.00	(0.13)	0.03	0.00	0.00	0.00	0.00
3.	Total Revenues	2,456.76	1,491.17	852.35	0.60	0.00	26.17	7.47	7.44	2.58	12.32	18.86	32.84	0.49	1.63	2.83
4.	Proposed 2010 Revenue Requirement	2,456.76	1,488.85	852.24	0.93	0.00	26.11	7.68	7.57	2.59	13.38	19.65	32.75	0.56	1.63	2.83
5.	Measure of Revenues vs Revenue Requirement	1.00	1.00	1.00	0.64	0.00	1.00	0.97	0.98	1.00	0.92	0.96	1.00	0.88	1.00	1.00

Measure of 2010 Revenues vs 2010 Revenue Requirement
Excluding Gas Supply Commodity
December 31, 2010

(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
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	RATE 325 & 330	DIRECT PURCHASE
1.	Sales and Delivery Revenue	1,398.33	888.27	451.93	0.32	0.00	17.61	6.64	7.44	1.41	7.45	3.14	9.17	0.49	1.63	2.83
2.	Unbilled Revenues	6.68	2.49	4.38	0.00	0.00	(0.08)	(0.02)	0.00	0.00	(0.13)	0.03	0.00	0.00	0.00	0.00
3.	Total Revenues	1,405.01	890.75	456.31	0.32	0.00	17.54	6.62	7.44	1.41	7.32	3.17	9.17	0.49	1.63	2.83
4.	Proposed 2010 Revenue Requirement	1,405.01	888.43	456.19	0.65	0.00	17.47	6.83	7.57	1.42	8.38	3.96	9.08	0.56	1.63	2.83
5.	Measure of Revenues vs Revenue Requirement excluding Gas Supply Commodity	1.00	1.00	1.00	0.50	0.00	1.00	0.97	0.98	1.00	0.87	0.80	1.01	0.88	1.00	1.00

Total 2010 Revenue Requirement

December 31, 2010

(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	Reference
1	PRODUCT COSTS	1,051.8	600.4	396.0	0.3	-	8.6	0.9	-	1.2	5.0	15.7	23.7	-	-	-	Ex.B/T4/S10/P4/L1 & Ex.B/T4/S10/P5/L1
2	PIPELINE TRANS. AND LOAD BALANCING	318.8	170.0	136.8	0.1	-	4.7	0.8	-	0.9	2.1	(1.9)	5.4	-	-	-	Ex.B/T4/S10/P4/L2 & Ex.B/T4/S10/P5/L2
3	STORAGE	146.8	74.8	66.2	0.0	-	1.5	0.4	-	(0.5)	1.2	1.6	1.7	-	-	-	Ex.B/T4/S10/P4/L3 & Ex.B/T4/S10/P5/L3
4	DISTRIBUTION	464.0	273.6	160.9	0.0	-	8.5	5.0	7.0	0.1	3.1	3.6	1.8	0.3	0.2	-	Ex.B/T4/S10/P4/L4 & Ex.B/T4/S10/P5/L4
5	CUSTOMER RELATED	473.7	370.1	92.4	0.6	0.0	2.8	0.7	0.6	0.9	2.0	0.7	0.1	0.1	0.0	2.83	Ex.B/T4/S10/P5/L5
Total 2010 Revenue Requirement		2,455.1	1,488.8	852.2	0.9	0.0	26.1	7.7	7.6	2.6	13.4	19.6	32.8	0.4	0.2	2.83	

2010 Gas Cost to Operations Revenue Requirement

December 31, 2010

(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	1,041.6	595.4	391.0	0.3	-	8.6	0.9	-	1.2	5.0	15.7	23.6	-	-	-	1.1
1	Total Gas Cost	1,041.6	595.4	391.0	0.3	-	8.6	0.9	-	1.2	5.0	15.7	23.6	-	-	-	
	PIPELINE TRANS. AND LOAD BALANCING																
2.1	Peak	12.1	6.4	5.5	0.0	-	0.1	0.0	-	-	-	-	0.1	-	-	-	3.1
2.2	Seasonal	11.8	5.7	5.2	-	-	0.2	0.0	-	-	0.2	0.3	0.2	-	-	-	3.2
2.3	Annual - Transportation	268.3	141.0	110.8	0.1	-	4.2	0.7	-	0.9	2.2	3.7	4.8	-	-	-	1.4
2.4	Seasonal Credit	(7.5)	-	-	-	-	-	-	-	-	(0.8)	(6.5)	(0.1)	-	-	-	
2	Total Pipeline Trans. Cost	284.7	153.1	121.5	0.1	-	4.4	0.8	-	0.9	1.6	(2.5)	4.9	-	-	-	
	STORAGE																
3.1	Deliverability	55.9	29.4	25.4	0.0	-	0.4	0.1	-	-	-	-	0.5	-	-	-	3.1
3.2	Space	57.2	27.9	25.3	-	-	0.8	0.2	-	-	0.9	1.3	0.8	-	-	-	3.2
3.3	Seasonal Credit	(0.5)	-	-	-	-	-	-	-	(0.5)	-	-	-	-	-	-	
3	Total Storage	112.5	57.3	50.8	0.0	-	1.1	0.3	-	(0.5)	0.9	1.3	1.3	-	-	-	
	DISTRIBUTION																
4.1	Commodity	14.4	6.0	5.8	0.0	-	0.7	0.6	-	0.1	0.3	0.7	0.2	-	-	-	1.3
4	Total Distribution	14.4	6.0	5.8	0.0	-	0.7	0.6	-	0.1	0.3	0.7	0.2	-	-	-	
	Total 2010 Gas Cost to Operations Revenue Requirement	1,453.2	811.8	569.1	0.3	-	14.9	2.5	-	1.7	7.8	15.1	30.1	-	-	-	

2010 Distribution Revenue Requirement

December 31, 2010

(millions of dollars)

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
	SUPPLY RELATED															
1	PRODUCT RELATED	10.2	5.0	5.0	0.0	-	0.0	0.0	-	0.0	0.1	0.0	0.0	-	-	-
2	LOAD BALANCING RELATED	34.1	16.9	15.3	(0.0)	-	0.3	(0.0)	-	(0.0)	0.5	0.7	0.5	-	-	-
	FACILITIES' COSTS															
3	STORAGE	34.3	17.5	15.4	0.0	-	0.3	0.1	-	-	0.2	0.3	0.4	-	-	-
4	DISTRIBUTION	449.7	267.6	155.1	0.0	-	7.7	4.5	7.0	0.0	2.8	2.9	1.6	0.3	0.2	-
5	CUSTOMER RELATED	473.7	370.1	92.4	0.6	0.0	2.8	0.7	0.6	0.9	2.0	0.7	0.1	0.1	0.0	2.83
Total Distribution Revenue Requirement		1,001.9	677.0	283.1	0.6	0.0	11.2	5.2	7.6	0.9	5.6	4.6	2.7	0.4	0.2	2.83

2010 Y- and Z- Factor Revenue Requirement

December 31, 2010

(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
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	Assignment
	Y Factor: Other																
1.1	2010 Gas in Storage & Working Cash Carrying Cost	36.7	17.92	16.27	-	-	0.49	0.12	-	-	0.59	0.81	0.51	-	-		3.2
1.2	DSM 2010	26.7	11.62	8.95	-	-	1.57	1.40	-	-	1.51	1.67	-	-	-		Direct
1.3	CIS/ Customer Care 2010	95.7	87.83	7.84	0.00	-	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00		4.1
		159.1	117.37	33.06	0.00	-	2.07	1.52	0.00	0.00	2.11	2.48	0.51	0.00	0.00		
	Y Factor: Capital Investment																
1.4	2010 Leave to Construct	3.6	1.67	1.49	0.00	-	0.07	0.05	0.25	0.00	0.02	0.01	0.04	0.00	-		2.1
		3.6	1.67	1.49	0.00	-	0.07	0.05	0.25	0.00	0.02	0.01	0.04	0.00	-		
1.5	Total Y-Factor: Other & Capital Investment	162.7	119.03	34.55	0.00	-	2.14	1.57	0.25	0.00	2.13	2.49	0.55	0.00	0.00		
	Z Factor: Proposed																
1.6	2010 Pension Funding requirement	18.9	12.81	5.36	0.01	0.00	0.21	0.10	0.14	0.02	0.11	0.09	0.05	0.01	0.00	-	ExB T4 S10 p7
1.7	2010 Crossbores/Sewer Laterals Program	3.6	2.51	1.02	0.00	-	0.04	0.01	0.00	0.00	0.01	0.01	-	0.00	0.00	-	2.3 & 4.2
1.8	Total Z-Factor (Proposed)	22.5	15.31	6.37	0.01	0.00	0.25	0.11	0.14	0.02	0.12	0.09	0.05	0.01	0.01	-	
1.9	Total All Y- & Z-Factors	185.2	134.35	40.92	0.01	0.00	2.39	1.68	0.39	0.02	2.25	2.58	0.60	0.01	0.01	-	

2010 Distribution Revenue Requirement with Y- and Z- Factor Detail
December 31, 2010

(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
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	
1.0	DRR before Y- & Z-Factors	816.7	542.7	242.2	0.6	0.0	8.8	3.5	7.2	0.9	3.4	2.0	2.1	0.4	0.2	2.8	
	Y Factor: Other																
1.1	2010 Gas in Storage & Working Cash Carrying Cost	36.7	17.9	16.3	-	-	0.5	0.1	-	-	0.6	0.8	0.5	-	-		
1.2	DSM 2010	26.7	11.6	8.9	-	-	1.6	1.4	-	-	1.5	1.7	-	-	-		
1.3	CIS/ Customer Care 2010	95.7	87.8	7.8	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	3.6	1.7	1.5	0.0	-	0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.0	-		
1.5	Total Y-Factor	162.7	119.0	34.5	0.0	0.0	2.1	1.6	0.2	0.0	2.1	2.5	0.5	0.0	0.0	0.0	
1.6	DRR with Y-Factors	979.4	661.7	276.8	0.6	0.0	11.0	5.1	7.4	0.9	5.5	4.5	2.6	0.4	0.2	2.8	
	Z Factor: Proposed																
1.7	2010 Pension Funding requirement	18.9	12.8	5.4	0.0	0.0	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-	allocated in proportion to Line 1.6
1.8	2010 Crossbores/Sewer Laterals Program	3.6	2.5	1.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	-	
1.9	Total Z-Factor (Proposed)	22.5	15.3	6.4	0.0	0.0	0.3	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.0	0.0	
2.0	Total DRR with All Y-& Z-Factors	1,001.9	677.0	283.1	0.6	0.0	11.2	5.2	7.6	0.9	5.6	4.6	2.7	0.4	0.2	2.8	

Allocators
December 31, 2010

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 16
	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 F	RATE 300 Int	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	5,301.8	3,030.6	1,990.4	1.4	0.0	43.9	4.4	0.0	5.9	25.2	79.7	120.3	0.0	0.0	0.0
1.2 Bundled Annual Deliveries	11,051.1	4,646.1	4,435.7	1.7	0.0	562.7	425.5	0.0	58.1	222.0	543.1	156.1	0.0	0.0	0.0
1.3 Total Annual Deliveries	11,092.1	4,646.1	4,435.7	1.7	0.0	562.7	425.5	0.0	58.1	222.0	543.1	156.1	0.0	41.0	0.0
1.4 Bundled Transportation Deliveries	6,767.7	3,555.4	2,794.4	1.7	0.0	105.0	17.8	0.0	22.9	55.5	94.6	120.3	0.0	0.0	0.0
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	104,754.3	48,501.0	43,446.9	4.9	0.0	2,127.4	1,325.7	7,175.4	6.7	626.1	274.0	1,166.0	100.1	0.0	0.0
2.2 Delivery Demand HP	96,538.8	48,501.0	43,446.9	4.9	0.0	2,127.4	1,325.7	0.0	6.7	626.1	274.0	0.0	100.1	125.9	0.0
2.3 Delivery Demand LP	95,835.9	48,501.0	43,446.9	4.9	0.0	2,127.4	622.8	0.0	6.7	626.1	274.0	0.0	100.1	125.9	0.0
2.4 Cust. Rel Plant	1,931,528.0	1,772,699.0	158,257.0	27.0	0.0	239.0	42.0	4.0	39.0	179.0	31.0	1.0	9.0	1.0	0.0
STORAGE RESPONSIBILITY															
3.1 Deliverability	52.0	27.4	23.7	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	2,601.1	1,269.7	1,152.9	0.0	0.0	34.6	8.7	0.0	0.0	41.9	57.4	35.9	0.0	0.0	0.0
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1,931,528.0	1,772,699.0	158,257.0	27.0	0.0	239.0	42.0	4.0	39.0	179.0	31.0	1.0	9.0	1.0	0.0
4.2 Services	1,841,600.0	1,633,137.8	205,380.0	82.8	0.0	1,104.4	374.1	1.7	238.9	776.1	441.9	0.0	48.1	14.3	0.0

Allocation Percentages
December 31, 2010

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
	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	0.5716	0.3754	0.0003	0.0000	0.0083	0.0008	0.0000	0.0011	0.0048	0.0150	0.0227	0.0000	0.0000	0.0000
1.2 Bundled Annual Deliveries	1.0000	0.4204	0.4014	0.0002	0.0000	0.0509	0.0385	0.0000	0.0053	0.0201	0.0491	0.0141	0.0000	0.0000	0.0000
1.3 Total Annual Deliveries	1.0000	0.4189	0.3999	0.0002	0.0000	0.0507	0.0384	0.0000	0.0052	0.0200	0.0490	0.0141	0.0000	0.0037	0.0000
1.4 Bundled Transportation Deliveries	1.0000	0.5254	0.4129	0.0003	0.0000	0.0155	0.0026	0.0000	0.0034	0.0082	0.0140	0.0178	0.0000	0.0000	0.0000
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	1.0000	0.4630	0.4148	0.0000	0.0000	0.0203	0.0127	0.0685	0.0001	0.0060	0.0026	0.0111	0.0010	0.0000	0.0000
2.2 Delivery Demand HP	1.0000	0.5024	0.4500	0.0001	0.0000	0.0220	0.0137	0.0000	0.0001	0.0065	0.0028	0.0000	0.0010	0.0013	0.0000
2.3 Delivery Demand LP	1.0000	0.5061	0.4533	0.0001	0.0000	0.0222	0.0065	0.0000	0.0001	0.0065	0.0029	0.0000	0.0010	0.0013	0.0000
2.4 Cust. Rel Plant	1.0000	0.9178	0.0819	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	0.5264	0.4551	0.0000	0.0000	0.0069	0.0020	0.0000	0.0000	0.0000	0.0000	0.0096	0.0000	0.0000	0.0000
3.2 Space	1.0000	0.4881	0.4432	0.0000	0.0000	0.0133	0.0033	0.0000	0.0000	0.0161	0.0221	0.0138	0.0000	0.0000	0.0000
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1.0000	0.9178	0.0819	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	0.8868	0.1115	0.0000	0.0000	0.0006	0.0002	0.0000	0.0001	0.0004	0.0002	0.0000	0.0000	0.0000	0.0000

Not Used

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 during the 2010 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 provided 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 Gas Distribution 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 2010 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	2 175.7	76.8
Ontario Production	1.5	0.0
Peaking	26.7	0.9
Chicago Supply	2 198.4	77.6
Delivered Supply	1 071.6	37.9
	5 473.9	193.2

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 July 17, 2009 to August 14, 2009 for the 12 months commencing January 1, 2010 and applied these monthly prices to the 2010 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, 2009 QRAM prices in a fashion similar to the 2009 Budget that was filed in EB-2008-0219.

8. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2010 PGVA. Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2010 PGVA. While the Company does not anticipate acquiring gas in 2010 via means other than the traditionally transportation paths (i.e., TCPL, Alliance/Vector) the possibility exists, if not this year but in the future, to acquire gas via alternative means (i.e., LNG, Shale Gas, Rockies).

<u>Peak Day Coverage</u>

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. These conditions are experienced, on average, about once every five years. Enbridge is forecasting a design peak day level of 97 997 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 had an expiry date during the test year were deemed to be renewed with two exceptions. In order to accommodate a level of Direct Purchase customer volumes which have returned to system supply the Company intends to acquire an additional 25,000 GJ/day of TCPL Long Haul FT capacity effective November 1, 2009. Also a portion of the Company's Vector capacity (142,000 Mmbtu/day) is scheduled to expire October 31, 2010. The Company has chosen only to renew 100,000 Mmbtu's /day

11. 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 project. The gas cost forecast assumed January 1, 2009 Union tolls.

Storage

12. 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.

13. 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. The Board ruled that as these contracts expired that they then could be replaced with market based storage.

14. Following that directive the Company issued a Request For Proposal ("RFP") for market based storage services to replace the first of the three contracts that expired March 31, 2008. Following the RFP process the Company settled on three separate storage contracts that came into effect April 1, 2008. The second of those three contracts expired March 31, 2009 and following an RFP process the Company settled on three separate storage contracts that came into effect April 1, 2009. This year the Company issued an RFP for market based storage to replace the third of the three contracts that will expire March 31, 2010. The Company is currently finalizing the details with one party for services to become effective April 1, 2010. The cost consequences of this storage contract has been included in the forecast for 2010 gas costs.

Energy Content

15. 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.

Schedules

16. The following schedules (pp. 1 and 2) provide the summary of the forecasted gas cost to operations for 2010 based upon an updated supply and transportation portfolio to meet the forecasted volumetric requirement for 2010. Page 3 provides a breakdown of the forecasted 2010 storage and transportation costs that are shown at Item #12, Column 2 of page 2. Page 4 provides a breakdown of the monthly gas in storage balances for rate base purposes in 2010. Pages 5 through 8 are the comparable schedules for 2009 assuming the October 1, 2009 QRAM Reference Price.

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2010

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	484,213.3	98,849.9	204.145	5.416
1.3	Western - @ Nova - TCPL	768,381.9	154,108.6	200.563	5.321
1.4	Western Buy/Sell - with Fuel	2,072.4	434.7	209.734	5.565
1.5	Western - @ Alliance	968,895.5	218,605.7	225.624	5.986
1.6	Less TCPL Fuel Requirement	(47,911.2)	0.0		
1.	Total Western Canadian Supplies	2,175,651.9	471,998.8	216.946	5.756
	Short Term Supplies				
2.	Peaking/Seasonal	26,740.0	9,908.1	370.536	9.831
3.	Ontario Production	1,460.1	352.3	241.275	6.402
	Chicago Supplies				
4.1	Vector 1st Tranche	11,975.5	2,721.0	227.217	6.029
4.2	Vector 2nd Tranche	807,280.4	184,737.1	228.839	6.072
4.3	Vector 3rd Tranche	1,379,159.4	313,435.7	227.266	6.030
4.	Total Chicago Supplies	2,198,415.3	500,893.8	227.843	6.045
	Delivered Supplies				
5.1	Link Supplies	-	-	0.000	0.000
5.2	Ontario Delivered	1,071,636.5	253,780.0	236.815	6.283
5.	Total Other Delivered Supplies	1,071,636.5	253,780.0	236.815	6.283
6.	Total Supply Costs	5,473,903.7	1,236,933.0	225.969	5.995
	Transportation Costs				
7.1	TCPL - FT - Demand		49,575.1		
7.2	- FT - Commodity	1,206,756.4	4,217.2	3.495	0.093
7.3	Capacity Discounts		0.0		
7.4	- STS - CDA		3,607.6		
7.5	- STS - EDA		3,731.9		
7.6	- Dawn to CDA Exchange		7,643.5		
7.7	- Dawn to EDA Exchange		12,054.7		
7.8	Other Charges		0.0		
7.9	Nova Transmission		2,151.9		
7.10	ANR/Michcon Transportation		0.0		
7.11	Link Pipeline		0.0		
7.12	Alliance Pipeline		41,100.6		
7.13	Vector Pipeline - 1st Tranche		9,518.6		
7.14	Vector Pipeline - 2nd Tranche		8,413.9		
7.15	Vector Pipeline - 3rd Tranche		11,757.2		
7.	Total Transportation Costs		153,772.2		
8.	Total Before PGVA Adjustment	5,473,903.7	1,390,705.3	254.061	6.741
9.	PGVA Adjustment		(92,514.4)		
10.	Total Purchases & Receipt	5,473,903.7	1,298,190.9	237.160	6.292

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2010

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	5,473,903.7	1,298,190.9	237.160	6.292
11.	Storage Fluctuation	(79,104.5)	(18,760.4)		
12.	Commodity Cost to Operations	5,394,799.2	1,279,430.5	237.160	
13.	Storage and Transportation Costs		110,171.4		
14.	Gas Cost to Operations	5,394,799.2	1,389,601.9	257.582	6.834
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		63,896.0		
17.	Forecasted Gas Costs	5,394,799.2	1,453,497.8	269.426	7.148
	Regulatory Adjustments				
18.	NGV Vehicles		0.0		
19.	LRAM Adjustment		0.0		
20.	Accounting Adjustments		0.0		
21.	Forecasted Utility Gas Costs	5,394,799.2	1,453,497.8	269.426	7.148

RECONCILIATION OF NATURAL GAS SENDOUT VOLUMES
TO SALES VOLUMES
YEAR ENDED DECEMBER 31, 2010

Item #		
1.	Sendout To Operations	5,394,799.2
2.	T-Service Volumes	5,710,084.2
3.	Total Sendout	11,104,883.4
4.1	Residential Sales	3,030,604.3
4.2	Commercial Sales	1,827,871.6
4.3	Industrial Sales	323,024.7
4.4	T-Service	5,713,460.4
4.5	Rate 200 T-Service (Gazifere)	35,835.2
4.6	Rate 200 Sales (Gazifere)	120,305.1
4.7	Company Use	5,677.4
4.8	Unaccounted For (UAF)	37,795.0
4.9	Unbilled Forecast - Sales	25,757.6
4.10	Unbilled Forecast - T-Service	(39,211.4)
4.11	Lost and Unaccounted For (LUF)	23,763.5
4.12	LUF Capitalized	0.0
4.	Total System Requirements	11,104,883.3

SUMMARY OF STORAGE & TRANSPORTATION COSTS
FISCAL 2010

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2010	Col. 2 Fiscal 2010 Storage Charges Recovered in Fiscal 2010	Col. 3 Fiscal 2009 Storage Charges Recovered in Fiscal 2010	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2010
	Storage				
1.1	Chatham D	136.9	73.5	62.6	136.1
1.2	Space	0.0	0.0	0.0	0.0
1.3	Peak	353.8	189.8	845.1	1,034.9
1.4	Injection	85.4	24.3	87.6	111.9
1.5	Withdrawal	75.5	75.5	0.0	75.5
1.6	Market Based Storage	22,748.6	12,205.7	7,712.8	19,918.5
1.7	Other	1,304.6	1,304.6	(550.2)	754.4
1.	Total Storage	24,704.7	13,873.4	8,157.8	22,031.2
	Transportation				
2.	Total Transportation	66,241.7	35,541.9	30,780.1	66,321.9
	Dehydration				
3.1	Demand	982.8	527.3	456.9	984.2
3.2	Commodity	185.2	185.2	0.0	185.2
3.	Total Dehydration	1,168.0	712.5	456.9	1,169.4
4.	Total Union Gas	92,114.5	50,127.8	39,394.7	89,522.5
	Fuel Costs				
5.1	Tecumseh	3,960.2	2,523.9	1,959.8	4,483.7
5.2	Union Storage	1,103.4	719.5	818.7	1,538.2
5.3	Union Transportation	14,257.9	13,593.3	1,033.7	14,627.0
5.	Total Fuel Costs	19,321.5	16,836.8	3,812.1	20,648.9
6.	Total Storage & Transportation	111,435.9	66,964.5	43,206.9	110,171.4
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				110,171.4

2010
GAS IN STORAGE
MONTH END BALANCES AND
AVERAGE OF MONTHLY AVERAGES

Item #		103m3	Value ($000)
Month end balances except @ January 1			
1.	January 1	1,615,596.3	452,248.2
2.	January	1,231,237.5	332,744.3
3.	February	900,127.1	231,547.6
4.	March	644,737.6	157,213.2
5.	April	683,364.8	173,437.1
6.	May	851,799.9	223,054.2
7.	June	1,118,055.0	296,935.9
8.	July	1,428,158.3	381,526.5
9.	August	1,763,790.0	472,276.3
10.	September	2,098,794.5	562,512.0
11.	October	2,295,181.1	617,746.6
12.	November	2,131,879.5	576,314.5
13.	December	1,694,700.9	454,385.8
14.		1,400,189.5	373,218.8

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2009

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	628,064.3	118,685.8	188.971	5.014
1.3	Western - @ Nova - TCPL	358,056.6	65,824.1	183.837	4.878
1.4	Western Buy/Sell - with Fuel	4,117.4	791.7	192.279	5.102
1.5	Western - @ Alliance	971,582.8	200,958.3	206.836	5.488
1.6	Less TCPL Fuel Requirement	(39,254.4)	0.0		
1.	Total Western Canadian Supplies	1,922,566.5	386,259.9	200.908	5.331
	Short Term Supplies				
2.	Peaking/Seasonal	15,480.0	12,145.8	784.613	20.818
3.	Ontario Production	1,460.1	327.2	224.113	5.946
	Chicago Supplies				
4.1	Vector 1st Tranche	11,975.5	2,501.6	208.892	5.542
4.2	Vector 2nd Tranche	809,492.2	170,781.5	210.974	5.598
4.3	Vector 3rd Tranche	1,454,852.4	306,935.4	210.974	5.598
4.	Total Chicago Supplies	2,276,320.1	480,218.4	210.963	5.597
	Delivered Supplies				
5.1	Link Supplies	-	-	-	-
5.2	Ontario Delivered	983,880.1	213,892.0	217.396	5.768
5.	Total Other Delivered Supplies	983,880.1	213,892.0	217.396	5.768
6.	Total Supply Costs	5,199,706.8	1,092,843.4	210.174	5.576
	Transportation Costs				
7.1	TCPL - FT - Demand		39,091.9		
7.2	- FT - Commodity	754,736.5	3,323.3	4.403	0.117
7.3	Capacity Discounts		0.0		
7.4	- STS - CDA		3,607.6		
7.5	- STS - EDA		2,202.0		
7.6	- Dawn to CDA Exchange		7,643.5		
7.7	- Dawn to EDA Exchange		12,054.7		
7.8	Union C1 Transportation		0.0		
7.9	Nova Transmission		1,966.4		
7.10	ANR/Michcon Transportation		0.0		
7.11	Link Pipeline		0.0		
7.12	Alliance Pipeline		41,102.0		
7.13	Vector Pipeline - 1st Tranche		9,484.8		
7.14	Vector Pipeline - 2nd Tranche		7,473.3		
7.15	Vector Pipeline - 3rd Tranche		11,278.9		
7.	Total Transportation Costs		139,228.4		
8.	Total Before PGVA Adjustment	5,199,706.8	1,232,071.8	236.950	6.287
9.	PGVA Adjustment		(0.0)		
10.	Total Purchases & Receipt	5,199,706.8	1,232,071.8	236.950	6.287

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2009

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	5,199,706.8	1,232,071.8	236.950	6.287
11.	Storage Fluctuation	(149,825.6)	(35,501.2)		
12.	Commodity Cost to Operations	5,049,881.3	1,196,570.6	236.950	
13.	Storage and Transportation Costs		110,811.7		
14.	Gas Cost to Operations	5,049,881.3	1,307,382.2	258.894	6.869
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		186,586.8		
17.	Forecasted Gas Costs	5,049,881.3	1,493,969.0	295.842	7.849
	Regulatory Adjustments				
18.	NGV Vehicles		0.0		
19.	LRAM Adjustment		0.0		
20.	Accounting Adjustments		0.0		
21.	Forecasted Utility Gas Costs	5,049,881.3	1,493,969.0	295.842	7.849

RECONCILIATION OF NATURAL GAS SENDOUT VOLUMES
TO SALES VOLUMES
YEAR ENDED DECEMBER 31, 2009

Item #		
1.	Sendout To Operations	5,049,881.3
2.	T-Service Volumes	6,348,352.9
3.	Total Sendout	11,398,234.2
4.1	Residential Sales	2,896,586.4
4.2	Commercial Sales	1,671,081.9
4.3	Industrial Sales	308,318.0
4.4	T-Service	6,320,785.2
4.5	Rate 200 T-Service (Gazifere)	32,505.3
4.6	Rate 200 Sales (Gazifere)	118,849.2
4.7	Company Use	5,319.4
4.8	Unaccounted For (UAF)	31,841.0
4.9	Unbilled Forecast - Sales	(5,878.2)
4.10	Unbilled Forecast - T-Service	(4,937.5)
4.11	Lost and Unaccounted For (LUF)	23,763.5
4.12	LUF Capitalized	0.0
4.	Total System Requirements	11,398,234.1

SUMMARY OF STORAGE & TRANSPORTATION COSTS
FISCAL 2009

		Col. 1	Col. 2	Col. 3	Col. 4
Item #	Units - $(000)	Storage & Transportation Charges Incurred in Fiscal 2009	Fiscal 2009 Storage Charges Recovered in Fiscal 2009	Fiscal 2008 Storage Charges Recovered in Fiscal 2009	Total Storage & Transportation Charges Recovered in Fiscal 2009
	Storage				
1.1	Chatham D	136.9	73.4	61.5	134.9
1.2	Space	811.2	434.8	809.7	1,244.5
1.3	Peak	1,005.6	539.0	868.3	1,407.2
1.4	Injection	96.1	28.1	79.6	107.7
1.5	Withdrawal	120.3	120.3	0.0	120.3
1.6	Market Based Storage	15,819.0	8,478.8	3,734.6	12,213.4
1.7	Other	588.3	588.3	(1,357.8)	(769.5)
1.	Total Storage	18,577.5	10,262.7	4,195.8	14,458.6
	Transportation				
2.	Total Transportation	65,424.7	35,066.8	29,374.2	64,114.5
	Dehydration				
3.1	Demand	982.8	526.8	444.4	971.2
3.2	Commodity	195.2	195.2	0.0	195.2
3.	Total Dehydration	1,178.0	722.0	444.4	1,166.4
4.	Total Union Gas	85,180.2	46,051.5	34,014.4	79,739.4
	Fuel Costs				
5.1	Tecumseh	6,303.2	3,919.6	1,384.8	5,304.5
5.2	Union Storage	1,905.2	1,306.7	555.0	1,861.8
5.3	Union Transportation	23,913.9	22,681.8	897.7	23,579.5
5.	Total Fuel Costs	32,122.3	27,908.1	2,837.6	30,745.7
6.	Total Storage & Transportation	117,302.5	73,959.7	36,852.0	110,811.7
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				110,811.7

2009
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	1,445,857.8
2.	January	1,048,580.1
3.	February	738,171.9
4.	March	498,943.7
5.	April	478,709.2
6.	May	594,764.0
7.	June	781,245.5
8.	July	1,118,763.1
9.	August	1,474,823.3
10.	September	1,789,988.9
11.	October	1,969,226.7
12.	November	1,910,620.2
13.	December	1,595,683.5
14.		1,160,383.9

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actuals at December 31, 2009 Principal ($000's)	Col. 2 Actuals at December 31, 2009 Interest ($000's)
	Non Commodity Related Accounts			
1.	Demand Side Management Account	2008 DSMVA	(73.3)	(56.0)
2.	Demand Side Management Account	2007 DSMVA	(616.1)	(126.5)
3.	Lost Revenue Adjustment Mechanism	2008 LRAM	37.3	-
4.	Lost Revenue Adjustment Mechanism	2007 LRAM	(301.3)	(3.4)
5.	Shared Savings Mechanism	2008 SSMVA	5,803.2	-
6.	Shared Savings Mechanism	2007 SSMVA	8,247.5	93.8
7.	Class Action Suit D/A	2009 CASDA	18,838.2	1,517.1 [1]
8.	Deferred Rebate Account	2009 DRA	2.7	(0.1)
9.	Deferred Rebate Account	2008 DRA	2,057.3	49.0
10.	Gas Distribution Access Rule Costs D/A	2009 GDARCDA	188.7	0.6 [2]
11.	Gas Distribution Access Rule Costs D/A	2008 GDARCDA	788.9	26.9 [2]
12.	Ontario Hearing Costs V/A	2009 OHCVA	533.9	0.1
13.	Ontario Hearing Costs V/A	2008 OHCVA	2,252.1	60.4
14.	Manufactured Gas Plant D/A	2009 MGPDA	206.6	10.5
15.	Unbundled Rates Customer Migration V/A	2008 URCMVA	485.7	5.5
16.	Open Bill Service D/A	2009 OBSDA	539.4	15.4
17.	Open Bill Access V/A	2009 OBAVA	476.7	5.4
18.	Open Bill Revenue V/A	2009 OBRVA	-	-
19.	Ex-Franchise Third Party Billing Services D/A	2009 EFTPBSDA	-	-
20.	Municipal Permit Fees D/A	2009 MPFDA	1,250.0	- [2]
21.	Municipal Permit Fees D/A	2008 MPFDA	717.6	- [2]
22.	Average Use True-Up V/A	2009 AUTUVA	5,626.9	-
23.	Average Use True-Up V/A	2008 AUTUVA	(2,654.1)	(30.2)
24.	Tax Rate and Rule Change V/A	2009 TRRCVA	(350.0)	-
25.	Earnings Sharing Mechanism D/A	2009 ESMDA	-	- [3]
26.	Earnings Sharing Mechanism D/A	2008 ESMDA	(5,600.0)	(65.0)
27.	International Financial Reporting Standards Transition Costs D/A	2009 IFRSTCDA	2,060.3	-
28.	Total non commodity related accounts		40,518.2	1,503.5
	Commodity Related Accounts			
29.	Purchased Gas V/A	2009 PGVA	(239,227.1)	(2,069.2) [4]
30.	Purchased Gas V/A	2008 PGVA	23,135.4	(797.7)
31.	Transactional Services D/A	2009 TSDA	(7,062.1)	(3.1)
32.	Transactional Services D/A	2008 TSDA	(6,476.0)	(90.6)
33.	Unaccounted for Gas V/A	2009 UAFVA	9,596.7	-
34.	Unaccounted for Gas V/A	2008 UAFVA	621.2	7.1
35.	Storage and Transportation D/A	2009 S&TDA	(1,591.3)	(3.1)
36.	Storage and Transportation D/A	2008 S&TDA	(1,826.8)	(125.9)
37.	Total commodity related accounts		(222,830.0)	(3,082.5)
38.	Total Deferral and Variance Accounts		(182,311.8)	(1,579.0)

Notes:

1. This is the CASDA balance at the end of 2009. In EB-2007-0731 the Board approved the clearance of the CASDA over 5 years with the first installment occurring in 2008. The second (2009) installment which was approved by the Board in EB-2009-0055, is now approved to be cleared in April and May 2010. The December 2009 balance therefore represents approximately four fifths of the total approved for clearance, with 1/5th already cleared in 2008, another 1/5th to be cleared commencing in April 2010 for the 2009 installment and another 1/5th to be cleared in July 2010 for the 2010 installment.

2. The balances in the GDARCDA and MPFDA accounts are annual expenditures (capital and O&M). Due to the capital component of these expenditures, the company will determine and request the clearance of associated annual revenue requirements, as it did and was approved for the 2008 GDARCDA and MPFDA amounts shown on page 2 of this exhibit.

3. A determination of any ESMDA requirement has not yet received the necessary audit and management approvals for meeting public disclosure rules.

4. The 2009 PGVA balance will continue to be cleared through rate Rider "C" until March 31, 2010. An analysis of any residual account balance and true up requirement will be provided along with the requested clearance beginning in July 2010, within the EGD 2009 Earnings Sharing Review Application.

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNTS
FOR FUTURE CLEARANCE

Line No.	Account Description	Account Acronym	Col. 1 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Principal ($000's)	Col. 4 Interest ($000's)
			Accounts anticipated to be cleared in April and May 2010		Current estimate of accounts to be cleared commencing July 1, 2010	
	Non Commodity Related Accounts					
1.	Demand Side Management Account	2008 DSMVA	-	-	(73.3)	(56.2)
2.	Demand Side Management Account	2007 DSMVA	(616.1)	(127.5)	-	-
3.	Lost Revenue Adjustment Mechanism	2008 LRAM	-	-	37.3	0.1
4.	Lost Revenue Adjustment Mechanism	2007 LRAM	(301.3)	(3.9)	-	-
5.	Shared Savings Mechanism	2008 SSMVA	-	-	5,803.2	16.2
6.	Shared Savings Mechanism	2007 SSMVA	8,247.5	107.0	-	-
7.	Class Action Suit D/A	2010 CASDA	-	-	4,709.5	411.9 [1]
8.	Class Action Suit D/A	2009 CASDA	4,709.5	411.9 [1]	-	-
9.	Deferred Rebate Account	2009 DRA	-	-	2.7	(0.1)
10.	Deferred Rebate Account	2008 DRA	2,057.3	52.3	-	-
11.	Gas Distribution Access Rule Costs D/A	2009 GDARCDA	-	-	-	- [2]
12.	Gas Distribution Access Rule Costs D/A	2008 GDARCDA	825.6	- [3]	-	-
13.	Ontario Hearing Costs V/A	2009 OHCVA	-	-	533.9	1.3
14.	Ontario Hearing Costs V/A	2008 OHCVA	2,252.1	64.0	-	-
15.	Unbundled Rates Customer Migration V/A	2008 URCMVA	485.7	6.3	-	-
16.	Open Bill Service D/A	2009 OBSDA	-	-	89.9	2.0
17.	Open Bill Access V/A	2009 OBAVA	-	-	79.5	1.0
18.	Open Bill Revenue V/A	2009 OBRVA	-	-	-	-
19.	Ex-Franchise Third Party Billing Services D/A	2009 EFTPBSDA	-	-	-	-
20.	Municipal Permit Fees D/A	2009 MPFDA	-	-	-	- [2]
21.	Municipal Permit Fees D/A	2008 MPFDA	99.6	- [3]	-	-
22.	Average Use True-Up V/A	2009 AUTUVA	-	-	5,626.9	15.6
23.	Average Use True-Up V/A	2008 AUTUVA	(2,654.1)	(34.4)	-	-
24.	Tax Rate and Rule Change V/A	2009 TRRCVA	-	-	(350.0)	(1.2)
25.	Earnings Sharing Mechanism D/A	2009 ESMDA	-	-	-	- [4]
26.	Earnings Sharing Mechanism D/A	2008 ESMDA	(5,600.0)	(74.0)	-	-
27.	International Financial Reporting Standards Transition Costs D/A	2009 IFRSTCDA	-	-	2,060.3	5.4
28.	Total non commodity related accounts		9,505.8	401.7	18,519.9	396.0
	Commodity Related Accounts					
29.	Purchased Gas V/A	2009 PGVA	-	-	-	- [5]
30.	Purchased Gas V/A	2008 PGVA	23,135.4	(760.6)	-	-
31.	Transactional Services D/A	2009 TSDA	-	-	(7,062.1)	(22.3)
32.	Transactional Services D/A	2008 TSDA	(6,476.0)	(101.0)	-	-
33.	Unaccounted for Gas V/A	2009 UAFVA	-	-	9,596.7	26.4
34.	Unaccounted for Gas V/A	2008 UAFVA	621.2	8.1	-	-
35.	Storage and Transportation D/A	2009 S&TDA	-	-	(1,591.3)	(7.3)
36.	Storage and Transportation D/A	2008 S&TDA	(1,826.8)	(128.8)	-	-
37.	Total commodity related accounts		15,453.8	(982.3)	943.3	(3.2)
38.	Total Deferral and Variance Accounts		24,959.6	(580.6)	19,463.2	392.8 [6]

Notes:

1. The balances shown in the 2009 and 2010 CASDA accounts represent the second (2009) and third (2010) installments of the CASDA balance approved for clearance over the five years (2008-2012) in EB-2007-0731. The second (2009) installment is approved for clearance commencing in April 2010 along with other 2008 deferral accounts. EGD is requesting clearance of the 2010 related installment commencing in July 2010.

2. The amounts to be requested for clearance in relation to the 2009 GDARCDA and 2009 MPFDA are to 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 2009 ESM review application and proceeding.

3. The balances in the 2008 GDARCDA and MPFDA accounts are the revenue requirements approved for clearance in the EB-2009-0055 proceeding.

4. A determination of any ESMDA requirement has not yet received the necessary audit and management approvals for meeting public disclosure rules.

5. The 2009 PGVA balance will continue to be cleared through rate rider "C" until March 31, 2010. Any residual balance and true up requirement, will be requested for clearance beginning in July 2010. As a result of the existing rider relating to the PGVA, its balance is not included in the total deferral and variance accounts balance currently shown for clearance to commence July 1, 2010.

6. The total does not include the 2009 GDARCDA, MPFDA, and PGVA impacts as explained in notes above.

DEFERRAL AND VARIANCE ACCOUNTS

A) EB-2009-0055 Clearance of Approved Deferral and Variance Accounts

1. Within the EB-2009-0055 proceeding and initial Decision, the Board approved the clearance of certain Deferral and Variance Accounts ("DA" and "VA") to occur in October and November of 2009. A supplementary decision and order issued by the Board on September 17, 2009, approved a delay in the timing of the clearance of those accounts as a result of the implementation of EGD's new Customer Information System. As part of the supplementary decision, the Board ordered that EGD should indicate within its January 2010 Quarterly Rate Adjustment Mechanism ("QRAM"), when it would be advisable to implement the clearance of these accounts. EGD has now received Board approval to clear these accounts in connection with the April 1, 2010 QRAM to occur in two equal installments in April and May of 2010. The following is the list of accounts:

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 ("S&TDA").

Non-Gas related DA's and VA's:

5. 2009 Class Action Suit DA ("CASDA"),
6. 2008 Deferred Rebate Account ("DRA"),
7. 2008 Gas Distribution Access Rule Costs DA ("GDARCDA")
8. 2008 Ontario Hearing Costs VA ("OHCVA"),
9. 2008 Unbundled Rates Customer Migration VA ("URCMVA"),

Witnesses: K. Culbert
A. Kacicnik
D. Small

10. 2008 Municipal Permit Fees DA ("MPFDA"),
11. 2008 Average Use True-Up VA ("AUTUVA"),
12. 2008 Earnings Sharing Mechanism DA (ESMDA"),

DSM related DA's and VA's:

13. 2007 Demand-Side Management VA ("DSMVA"),
14. 2007 Lost Revenue Adjustment Mechanism ("LRAM"), and
15. 2007 Shared Savings Mechanism VA ("SSMVA").

2. Within the EB-2009-0043 Open Bill Access proceeding the Board approved a settlement whereby the balances in the 2008 Open Bill deferral and variance accounts would be transferred to 2009 accounts.

3. The DSM audit results and settlement proposal in relation to the 2008 DSMVA, LRAM, and SSMVA accounts received a January, 2010 Board approval for clearance of these accounts commencing July 1, 2010. Information on the impacts of the clearance of these and other accounts will be included within EGD's 2009 Earnings Sharing Mechanism application, which will address the review of approved deferral and variance accounts for clearance.

B) <u>2009 Test Year Approved Deferral and Variance Accounts</u>

4. The following list represents the 2009 Board approved deferral and variance accounts for the 2009 fiscal year for Enbridge, divided into three groupings - Gas related, Non-Gas related, and DSM related:

Gas related DA's and VA's:

1. 2009 Purchased Gas VA ("PGVA"),

Witnesses: K. Culbert
A. Kacicnik
D. Small

2. 2009 Transactional Services DA (“TSDA”),
3. 2009 Unaccounted for Gas VA (“UAFVA”), and
4. 2009 Storage and Transportation (“S&TDA”), and
5. 2009 Change in Purchased Gas Variance Disposition Methodology Deferral Account (“CPGVDMDA”),

Non-Gas related DA’s and VA’s:

6. 2009 Carbon Dioxide Offset Credits DA (“CDOCDA”),
7. 2009 Class Action Suit DA (“CASDA”),
8. 2009 Deferred Rebate Account (“DRA”),
9. 2009 Electric Program Earnings Sharing DA (“EPESDA”),
10. 2009 Gas Distribution Access Rule Costs DA (“GDARCDA”)
11. 2009 Manufactured Gas Plant DA (“MGPDA”),
12. 2009 Municipal Permit Fees DA (“MPFDA”),
13. 2009 Ontario Hearing Costs VA (“OHCVA”),
14. 2009 Unbundled Rate Implementation Cost DA (“URICDA”),
15. 2009 Unbundled Rates Customer Migration VA (“URCMVA”),
16. 2009 Average Use True-Up VA (“AUTUVA”),
17. 2009 Tax Rate and Rule Change VA (“TRRCVA”),
18. 2009 Earnings Sharing Mechanism DA (ESMDA”),
19. 2009 International Financial Reporting Standards Transition Costs Deferral Account (“IFRSTCDA”),
20. 2009 Open Bill Service DA (“OBSDA”),
21. 2009 Open Bill Access VA (“OBAVA”),
22. 2009 Open Bill Revenue VA (“OBRVA”),
23. 2009 Ex-Franchise Third Party Billing Services DA (“ETPBSDA”), and
24. 2009 Mean Daily Volume Mechanism Deferral Account (“MDVMDA”)

Witnesses: K. Culbert
A. Kacicnik
D. Small

DSM related DA's and VA's:

25. 2009 Demand-Side Management VA ("DSMVA"),
26. 2009 Lost Revenue Adjustment Mechanism ("LRAM"), and
27. 2009 Shared Saving Mechanism VA ("SSMVA").

C) <u>Clearance of Deferral and Variance Accounts July 1, 2010</u>

5. The establishment of the following DA's and VA's was approved by the Board in various earlier proceedings and accounting order requests. Within the following list of those accounts the Board has already approved the clearance of certain amounts within the 2009 CASDA, the 2009 OBSDA and OBAVA, and the 2008 DSMVA, LRAM and SSMVA. The Company will apply for a review and approval of the remaining accounts shown for clearance at July 1, 2010 within any 2009 Earnings Sharing Mechanism application.

1. 2009 Purchased Gas VA ("PGVA"),
2. 2009 Transactional Services DA ("TSDA"),
3. 2009 Unaccounted for Gas VA ("UAFVA"),
4. 2009 Storage & Transportation DA ("S&TDA"),
5. 2009 Carbon Dioxide Offset Credits DA ("CDOCDA"),
6. 2009 / 2010 Class Action Suit DA ("CASDA"),
7. 2009 Deferred Rebate Account ("DRA"),
8. 2009 Electric Program Earnings Sharing DA ("EPESDA"),
9. 2009 Gas Distribution Access Rule Costs DA ("GDARCDA"),
10. 2009 Municipal Permit Fees DA ("MPFDA"),
11. 2009 Ontario Hearing Costs VA ("OHCVA"),
12. 2009 Unbundled Rate Implementation Cost DA ("URICDA"),
13. 2009 Unbundled Rates Customer Migration VA ("URCMVA"),

Witnesses: K. Culbert
A. Kacicnik
D. Small

14. 2009 Average Use True-Up VA (“AUTUVA”),
15. 2009 Tax Rate and Rule Change VA (“TRRCVA”),
16. 2009 Earnings Sharing Mechanism DA (“ESMDA”),
17. 2009 Open Bill Service DA (“OBSDA”)
18. 2009 Open Bill Access VA (“OBAVA”)
19. 2009 Open Bill Revenue VA (“OBRVA”)
20. 2009 Ex-Franchise Third Party Billing Services DA (“ETPBSDA”)
21. 2009 International Financial Reporting Standards Transition Costs DA (“IFRSTCDA”)
22. 2008 Demand-Side Management VA (“DSMVA”),
23. 2008 Lost Revenue Adjustment Mechanism (“LRAM”), and
24. 2008 Shared Savings Mechanism VA (“SSMVA”).

6. The balances accumulated at the end of December, 2009 and approved to be cleared commencing July 1, 2010, will be included within the Company’s July 1, 2010 QRAM filing. As part of the July 1, 2010 deferral and variance account clearing, a one time true up of the 2009 PGVA year end related variances will be cleared across the appropriate types of service and customer classes.

7. Of the remaining accounts, not all are currently being requested for clearance:
   - The balance in the 2009 Manufactured Gas Plant DA (“MGPDA”) will be transferred into a 2010 MGPDA in order to bring forward the accumulated balance in the 2009 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, 2010.

- 2009 Demand-Side Management VA ("DSMVA"),
- 2009 Lost Revenue Adjustment Mechanism ("LRAM"),
- 2009 Shared Savings Mechanism VA ("SSMVA").

8. The 2009 Change in Purchased Gas Variance Disposition Methodology Deferral Account was approved to be established within the Decision and Order of the Board within the EB-2008-0106 Commodity Pricing, Load Balancing, and Cost Allocation Methodologies proceeding. Within that decision, the Board ordered EGD to record the costs of implementing a change in the disposition methodology for clearing the PGVA balance, for which costs would be reviewed and disposition determined in a subsequent proceeding. Given the nature and timing of the PGVA disposition change requirement, EGD does not believe that a review of related costs is likely to occur in time for a July 1, 2010 clearance, however, EGD will bring forward a proposal for timing of clearance as soon as possible.

9. The 2009 Mean Daily Volume Mechanism Deferral Account was also approved to be established within the Decision and Order of the Board within the EB-2008-0106 Commodity Pricing, Load Balancing, and Cost Allocation Methodologies proceeding. Within that decision, the Board ordered EGD to record the costs of implementing changes to the MDV mechanism in a deferral account, the disposition of which is to be decided in a subsequent proceeding. Given the required timing of the future MDV mechanism proposal which EGD is required to bring before the Board, EGD does not believe that a review of related costs can occur in time for a July 1, 2010 proposed clearance.

Witnesses: K. Culbert
A. Kacicnik
D. Small

10. Due to changes implemented by the Federal government with respect to certain capital cost allowance tax deductibility rates within 2009, EGD has recorded an amount within a 2009 Tax Rate and Rule Change Variance Account which is to the credit of ratepayers. The Company has filed evidence explaining the required and proposed treatment of this account (Updated 2010-01-22, Exhibit C, Tab 1, Schedule 4). The Company will be requesting clearance of the account commencing July 1, 2010.

11. 2009 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 2010 the Company will clear approximately one third of the remaining balance in the 2009 CASDA.

12. 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, in July 2010 the Company will clear approximately one third of the remaining balance in the 2009 OBSDA and 2009 OBAVA.

Witnesses: K. Culbert
A. Kacicnik
D. Small

13. A summary of the actual DA and VA balances to be cleared, some commencing in April 2010 as already approved by the Board and others at July 1, 2010, is included at Exhibit B, Tab 7, Schedule 1, pages 1 and 2.

D) 2010 Deferral and Variance Accounts Proposed

14. The Company has reviewed the existing, and potential requirement for, deferral or variance accounts during the incentive regulation period and the following is the list requested by the Company for the 2010 fiscal year, divided into three groupings - Gas related, Non-Gas related, and DSM related:

Gas related DA's and VA's

1. 2010 Purchased Gas VA ("PGVA"),
2. 2010 Transactional Services DA ("TSDA"),
3. 2010 Unaccounted for Gas VA ("UAFVA"),
4. 2010 Storage and Transportation DA ("S&TDA"), and
5. 2010 Change in Purchased Gas Variance Disposition Methodology DA ("CPGVDMDA"),

Non-Gas related DA's and VA's

6. 2010 Carbon Dioxide Offset Credits DA ("CDOCDA"),
7. 2010 Class Action Suit DA ("CASDA"),
8. 2010 Deferred Rebate Account ("DRA"),
9. 2010 Electric Program Earnings Sharing DA ("EPESDA"),
10. 2010 Gas Distribution Access Rule Costs DA ("GDARCDA"),
11. 2010 Manufactured Gas Plant DA ("MGPDA"),
12. 2010 Municipal Permit Fees DA ("MPFDA"),
13. 2010 Ontario Hearing Costs VA ("OHCVA"),
14. 2010 Unbundled Rate Implementation Cost DA ("URICDA"),

15. 2010 Unbundled Rates Customer Migration VA (“URCMVA”),
16. 2010 Average Use True-Up VA (“AUTUVA”),
17. 2010 Tax Rate and Rule Change VA (“TRRCVA)
18. 2010 Earnings Sharing Mechanism DA (“ESMDA”),
19. 2010 International Financial Reporting Standards Transition Costs DA (“IFRSTCDA”),
20. 2010 Open Bill Service DA (“OBSDA”),
21. 2010 Open Bill Access VA (“OBAVA”)
22. 2010 Open Bill Revenue VA (“OBRVA”)
23. 2010 Ex-Franchise Third Party Billing Services DA (“ETPBSDA”),
24. 2010 Mean Daily Volume Mechanism DA (“MDVMDA”),
25. 2010 Pension Funding Cost VA (“PFCVA”),
26. 2010 Crossbores / Sewer Laterals Bore VA (“SLCBVA”)

<u>DSM related DA’s and VA’s</u>

27. 2010 Demand-Side Management VA (“DSMVA”),
28. 2010 Lost Revenue Adjustment Mechanism (“LRAM”), and
29. 2010 Shared Savings Mechanism VA (“SSMVA”).

15. All 2010 deferral and variance accounts which continue over from their approval in 2009 or prior will continue to be determined / calculated in the same manner as previously established. Descriptions of the accounts will form part of the Company’s draft rate order submission.

<u>D) New Deferral Accounts</u>

16. EGD is requesting the establishment of a Pension Funding Cost Variance Account (“PFCVA”) for the recording of any variance between actual pension funding

requirements and those recovered in rates as a Z-factor. Exhibit C, Tab 1, Schedule 2 provides further explanation of the manner in which the account is proposed to operate.

17. EGD is also requesting the establishment of a Crossbores/Sewer Laterals Variance Account ("CBSLVA") for the recording of any variance between actual crossbores/sewer laterals costs and those recovered in rates as a Z-factor. Exhibit C, Tab 1, Schedule 3 provides further explanation of the manner in which the account is proposed to operate. The Company would look to provide the proposed treatment of recovery of such amounts within a future fiscal year proceeding / application.

Witnesses: K. Culbert
A. Kacicnik
D. Small

PENSION FUNDING COST VARIANCE ACCOUNT

1. The Company filed evidence at Exhibit B, Tab 3, Schedule 1 explaining the request of a Z factor in relation to its pension funding position.

2. The Company is requesting $18.9 million of pension funding requirement to be included within the IR revenue determination for recovery within rates in 2010. The amount is based upon an estimate of a December 31, 2008 valuation of the pension fund and potential pension funding obligations.

3. In conjunction with this request we are also proposing a 2010 variance account treatment around the amount. The reason for this is that the actual December 31, 2009 valuation and funding requirement will not be available until February 2010 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 3, Schedule 1 for further details and explanation of the Company's proposal.

Witnesses: K. Culbert
J. Haberbusch
N. Kishinchandani

CROSSBORES / SEWER LATERALS COST VARIANCE ACCOUNT

1. The Company filed evidence at Exhibit B, Tab 3, Schedule 2 explaining the request of a Z-factor in relation to the crossbores / sewer laterals initiative which the Company will be undertaking.

2. While the Company is requesting an amount to be included within the IR revenue determination for recovery within rates, EGD is also requesting a variance account treatment of the issue and related amounts.

3. For each year which a Z-factor treatment and amount is approved for recovery, EGD is proposing that the amount included in rates, which will be a revenue requirement determined using forecast information, will be trued up after the end of the fiscal year using actual information with any difference in revenue requirement to be recorded in a variance account for future clearance to ratepayers.

4. This will ensure that ratepayers are paying no more than the actual cost of the required program.

Witnesses: C. Clark
K. Culbert
L. Lawler

UPDATED EVIDENCE

UPDATE OF SHARING OF TAX CHANGE SAVINGS FORECAST AMOUNTS

1. The following schedule has been prepared and filed in accordance with EGD's 2008 Test Year, EB-2007-0615, Board Approved Settlement Proposal, filed herein at Exhibit E, Tab 1, Schedule 1.

2. Exhibit N1, Tab 1, Schedule 1, pages 22 and 23 of the EB-2007-0615 Settlement Proposal, identifies the tax sharing agreement for the Company's incentive regulation term. The agreement details the equal sharing (50/50) between ratepayer and the Company's shareholders, of tax savings relating to changes in tax rules and rates anticipated at that time and any subsequent changes.

3. Within the EB-2007-0615 Rate Order dated May 15, 2008, Schedule 1, page 1, the then forecast and agreed to levels of total tax savings and amounts to be shared were identified at Appendix A.

4. At that time, the tax savings agreement took account of purchases of certain computer equipment previously considered within CCA class 45 at 45% changing to class 45/50 at 55%. A new class, 52, has since been passed into law and allows for a 100% write off (with no half year rule), of such purchases between January 28, 2009 and February 1, 2011.

5. Additionally, the original tax savings adjustments had assumed and incorporated an expectation of certain effective total corporate income tax rates and provincial capital tax rates.

Witness: K. Culbert

6. The total corporate income tax rates anticipated within the original agreement have changed as a result of subsequent provincial income tax rate changes. The original anticipated total income tax rate of 32.00% for 2010 included a provincial tax rate of 14.00% throughout 2010. The provincial tax rate will now become 12.00% at July 1, 2010 as a result of tax legislation, Bill 218, which received Royal Assent in December 2009. The result is an average provincial income tax rate of 13.00% for 2010 which is 1.00% lower than the 14.00% rate included within the original tax savings calculations and results in a change in the total corporate income tax rate assumed for 2010 from 32.00% to 31.00%. A provincial income tax rate of 14.00% was also assumed in effect throughout 2011 and 2012 within the original agreement. Within the tax legislation, in addition to the provincial tax rate change at July 1, 2010 to 12.00%, there were also changes to the tax rate effective July 1, 2011 to 11.50%, and July 1, 2012 to 11.00% the effects of which have been taken account of in this updated sharing of tax change savings forecast evidence.

7. The provincial capital tax rate included within the original agreement assumed a rate of 0.150% effective throughout 2010 becoming zero at the start of 2011. We have since become aware that the capital tax rate approved for 2010 is 0.150% for January 1, 2010 to July 1, 2010, which becomes zero as of July 1, 2010. This results in an effective 2010 capital tax rate of 0.075%.

8. The result of these changes impacts the amount of tax savings that were anticipated in the years 2009 through 2012 in the EB-2007-0615 Approved Settlement Proposal and Board Rate Order. An updated tax sharing, incorporating the effects of the above noted tax rule and rate changes is provided at page 4 of this exhibit, while page 5 provides a copy of the originally approved schedule for reference purposes.

Witness: K. Culbert

9. The updated cumulative annual shared tax savings amounts resulting from this change are shown at Line 50, Columns 2 through 5 on page 4. The original agreed upon cumulative annual shared amounts are shown at Line 51 on page 4, and at Line 45 on page 5, which is a copy of the EB-2007-0615 Rate Order Schedule 1, Appendix A. This update changes the shared tax savings amounts in the year 2009 through 2012.

10. The impact for 2009 is that the original forecast tax savings, in the amount of $9.25 million (Line 51, Col. 2, p. 4), now becomes $9.60 million (Line 50, Col. 2, p. 4). The increase of $0.35 million (Line 52, Col. 2, p. 4) has been credited to the 2009 Tax Rate and Rule Change Variance Account ("TRRCVA").

11. The updated incremental ratepayer tax savings amounts for 2010, 2011, and 2012, which will be incorporated into ongoing rates, are shown at Lines 53 to 55 of Columns 3 to 5 respectively, on page 4 of this exhibit. The original incremental ratepayer tax savings amounts for 2010, 2011 and 2012 are shown at Line 44, Columns 3 to 5, at page 5 of this exhibit.

Schedule 1

Updated Summary - Sharing of Tax Change Forecast Amounts

(Incorporates new CCA Class 52, and changes in provincial income and capital tax rates between 2010 and 2012)

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
		2008	**2009**	**2010**	**2011**	**2012**	
	Tax Related Amounts Forecast from CCA Rate Changes **($ Millions)**						
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45/50) - Opening UCC Balance	1.54	2.24	1.14	0.51	1.64	
6.	New purchases (2007 Board Approved additions) -**with update for new Class 52**	2.13	2.13	2.13	2.13	2.13	
7.	**Re-grouping of amounts eligible for Class 52 (included at line 11)**	-	(1.95)	(2.13)	(0.18)	-	
8.	Capital Cost Allowance (CCA) at 55% -2007 Federal Budget tax rule CCA rate	1.43	1.28	0.63	0.82	1.49	
9.	Closing Undepreciated Capital Cost (UCC)	2.24	1.14	0.51	1.64	2.28	
10.	Computer Equipment (**New Class 52**) - Opening UCC Balance	-	-	-	-	-	
11.	New purchases (2007 Board Approved additions) -**with update for new Class 52**	-	1.95	2.13	0.18	-	
12.	Capital Cost Allowance (CCA) at 100% -2007 Federal Budget tax rule CCA rate	-	1.95	2.13	0.18	-	
13.	Closing Undepreciated Capital Cost (UCC)	-	-	-	-	-	
14.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.76	687.71	898.86	1101.57	
15.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
16.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
17.	Closing Undepreciated Capital Cost (UCC)	467.76	687.71	898.86	1101.57	1296.16	
18.	Distribution Assets (Class 51) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
19.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
20.	Capital Cost Allowance (CCA) at 6% -2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
21.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
22.	CCA Difference	7.27	12.82	15.85	17.29	20.67	
23.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	31.00%	28.25%	26.25%	
24.	Tax Impact	2.44	4.23	4.91	4.89	5.43	
25.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.65	6.31	7.12	6.81	7.36	31.26
26.	Incremental Amount	3.65	2.66	0.81	(0.31)	0.55	
27.	**50% of the Amount to Reduce Rates**	**$1.83**	**$1.33**	**$0.40**	**-$0.16**	**$0.28**	
	Tax Related Amounts Forecast from Income Tax Rate Changes						
28.	Taxable Income (2007 Board Approved, Final Rate Order, App.A, S3,P3,L15)	355.6	355.6	355.6	355.6	355.6	
29.	Gross Deficiency (2007 Board Approved, Final Rate Order, App.A, S1,P1,L7)	42.7	42.7	42.7	42.7	42.7	
30.	Interest Expense (2007 Board Approved, Final Rate Order, App.A, S3,P3,L25)	(165.90)	(165.90)	(165.90)	(165.90)	(165.90)	
31.	Board Approved Taxable Income for Income Tax Expense Calculation	232.40	232.40	232.40	232.40	232.40	
32.	2007 Approved Tax Rate (2007 Board Approved, Final Rate Order, App.A, S3,P3,L27)	36.12%	36.12%	36.12%	36.12%	36.12%	
33.	Anticipated Tax Rates During the IR Term	33.50%	33.00%	31.00%	28.25%	26.25%	
34.	Tax Rate Variance	2.62%	3.12%	5.12%	7.87%	9.87%	
35.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	11.90	18.29	22.94	
36.	Grossed-up Tax Savings	9.16	10.82	17.25	25.49	31.11	93.83
37.	Incremental Amount	9.16	1.66	6.43	8.24	5.62	
38.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$3.22**	**$4.12**	**$2.80**	
	Tax Related Amounts Forecast from Capital Tax Rate Changes						
39.	2007 Taxable Capital as Filed (EB-2006-0034, D3,T1,S1,P6,L7)	3,571.0	3,571.0	3,571.0	3,571.0	3,571.0	
40.	2007 Decision and Settlement Agreement Adjustments to Taxable Capital	(118.8)	(118.8)	(118.8)	(118.8)	(118.8)	
41.	2007 Board Approved Taxable Capital	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
42.	2007 Board Approved Capital Tax Rate (EB-2006-0034, D3,T1,S1,P6,L8)	0.285%	0.285%	0.285%	0.285%	0.285%	
43.	Anticipated Capital Tax Rates During the IR Term	0.225%	0.225%	0.075%	0.000%	0.000%	
44.	Capital Tax Rate Variance	0.060%	0.060%	0.210%	0.285%	0.285%	
45.	Annual Capital Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	2.07	2.07	7.25	9.84	9.84	31.07
46.	Incremental Amount	2.07	0.00	5.18	2.59	0.00	
47.	**50% of the Amount to Reduce Rates**	**$1.03**	**$0.00**	**$2.58**	**$1.30**	**$0.00**	
48.	**Cumulative Total Forecast Tax Related Amount (lines 25+36+45)**	**14.88**	**19.20**	**31.62**	**42.14**	**48.31**	156.16
49.	**Total Incremental Ratepayer Amounts into rates (lines 26+37+46)**	**$7.44**	**$2.16**	**$6.20**	**$5.26**	**$3.08**	
50.	**Total Updated Annual Ratepayer & Company Shareholder Tax Savings (50% of row 48)**	**$7.44**	**$9.60**	**$15.80**	**$21.06**	**$24.14**	$78.04
51.	***Total Original Agreement Annual Ratepayer Tax Savings***	***$7.44***	***$9.25***	***$12.91***	***$18.34***	***$20.91***	*$68.85*
52.	Amount to be credited to 2009 TRRCVA for return to ratpayers ($9.60M - $9.25M) (col.2, line 50 - 51)		$0.35				
53.	Ratepayer share of 2010 incremental tax amounts ($15.80 - $9.25) (col.3, line 50 - col.2, line 51)			6.55			
54.	Ratepayer share of 2011 incremental tax amounts ($21.06M - $15.80M) (col.4, line 50 - col.3, line 50)				$5.26		
55.	Ratepayer share of 2012 incremental tax amounts ($24.14M - $21.06M) (col.5, line 50 - col.4, line 50)					$3.08	

Originally
EB-2007-0615
Draft Rate Order
Schedule 1

Schedule 1

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**					

SERVICE QUALITY REQUIREMENTS

1. The purpose of this evidence is to review the filed results for the selected Service Quality Requirements in 2007 and 2008 and discuss what action has been taken to remediate the identified gaps.

Rescheduling Missed Appointments

2. The Ontario Energy Board's ("Board") Gas Distribution Access Rule ("GDAR"), Service Quality Requirements Performance and Measurement ("SQR") establishes the standards for Time to Reschedule Missed Appointments (TRMA). Under Section 7.3.4.2 of GDAR the distributor must attempt to contact the customer to reschedule the work within 2 hours of the end of the original appointment time, 100% of the time.[1]

3. As outlined in the Company's April 28, 2009 letter to the Board's Chief Regulatory Auditor, the performance versus target on TRMA, improved from 57.7% in 2007 to 62.8% in 2008. These results represent the number of customers that the Company contacted within the 2 hours of the end of the appointment time divided by the total number of missed appointments.

4. To improve the Company's performance, EGD formed an ongoing cross functional team to focus on the reasons for missing the original appointments. The team consists of 14 members from different regions, as well as employees of Lakeside Gas, the service contractor performing the work in the field. All missed appointments have been reviewed to prevent reoccurrence. A refresher training

[1] Rescheduling Missed Appointments was introduced in 2007 as a reported target under the Board's Appendix A, S.2.1.9 SQR Form, Section D.2 Time To Reschedule a Missed Appointment ("TRMA").

session was also held with the field staff at the beginning of the year to emphasize the importance of the metric. Improvement has been made despite implementations of a new Distribution Service contract in early 2009 and a new Customer Information System in September 2009. The increased attention to this SQR resulted in a significant improvement of the score compared to the previous years. The preliminary estimate for 2009 is 81.6% and will be finalized February 1, 2010.

5. At the same time, it should be noted that, the Company has consistently exceeded the SQRs target for S.2.1.9.D.1 Appointments Met Within the Designated Time Period (“AMWDTP”) and S.2.1.9.E.1 Percentage of Emergency Calls Responded Within One Hour (“ECRWOH”). Exceeding these targets and attending the initial call in the designated time frame improves overall customer service and reduces the absolute number of calls requiring rescheduling.

TABLE 1: SQR TARGETS

Year	2007	2008	2009 Preliminary
AMWDTP Target	85%	85%	85%
AMWDTP Actual	89.4%	93.7%	96.2%
ECRWOH Target	90%	90%	90%
ECRWOH Actual	91.4%	94.2%	95.8%

6. The Company believes that while rescheduling missed appointments is an important part of SQR, achievement of 100% target for TRMA is not always possible.

Witnesses: T. Ferguson
K. Lakatos-Hayward
B. Visnjevac

7. As the data shows, significant resources are being dedicated to improving the TRMA metric and to meeting or exceeding the related SQRs mentioned in Table 1. The Company would recommend that the target for SQR 2.1.9.D.2 be reviewed and would further propose that a target level of 90% would be more appropriate and achievable, while retaining the targets for the remaining SQRs.

Meter Reading Performance

8. In the Board's Appendix A S.2.1.9 SQR Form, Section C Meter Reading Performance ("MRP"), the number of meters that have not been read for four or more consecutive months may not exceed 0.5% of the total number of meters on a yearly basis.

9. Enbridge has previously reported that the number of meters not read for four consecutive months was 0.57% in 2007 and 0.69% in 2008 and that neither of these results meets the required performance metric of 0.5%. In 2007, the Company changed meter reading providers mid year. In 2008, record breaking snowfalls caused many meters to be inaccessible, a factor that contributed to the majority of the missed reads. Since that time, several initiatives to improve performance have been undertaken. These include upgrading handheld devices and meter reading software, increasing the number of "off cycle" reads that have been completed, and contacting customers to arrange access to meters.

10. The Company can report that it has met the Meter Reading Performance target in 2009, with a final result of 0.47%. The target was achieved in 2009 as a result of the continuation of initiatives implemented by the Company in 2008 as well as performing a detailed analysis of 4 or more consecutive estimate accounts, in addition to developing action plans to obtain meter reads for these accounts.

Witnesses: T. Ferguson
K. Lakatos-Hayward
B. Visnjevac

<u>2008 HISTORICAL RESULTS AND ASSOCIATED INFORMATION</u>

1. The Company's Fiscal 2008 Historical Utility financial results and supporting customer, volumetric, revenue and cost information were filed, reviewed and approved by the Board within the 2008 Earnings Sharing Mechanism proceeding, docket number EB-2009-0055.

2. The Company will provide an electronic copy of the evidence and results of that proceeding upon request.

Witness: K. Culbert

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	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	Total DRR	934.8	627.1	244.3	1.2	25.5	10.4	7.9	3.5	0.7	4.6	5.1	2.1	0.3	0.2	1.6
	Y Factor: Other															
1.1	2008 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2008 Board Approved Amount	23.1	11.2	5.8	-	2.3	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2008	89.2	81.7	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2008 Leave to Construct	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	
	Total Y-Factor Revenue requirement	155.3	113.0	30.6	0.0	4.6	1.3	1.5	(0.0)	0.1	1.1	2.5	0.5	0.0	0.0	-
	Total DRR minus Y-Factor	779.5	514.0	213.6	1.2	20.9	9.2	6.4	3.5	0.6	3.5	2.6	1.6	0.3	0.2	1.6

Estimated Assignment of 2008-2012 Distribution Revenue (With and Without Y Factors) to Rate Classes

2009

Col. 1 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	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	Total DRR	1,029.1	688.8	268.1	1.3	28.2	11.4	8.6	6.5	0.7	5.0	5.4	2.4	0.4	0.2	1.6
	Y Factor: Other															
1.1	2012 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2012	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2012	89.2	82.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2012 Leave to Construct	2.9	1.3	1.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	159.5	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	-
	Total DRR minus Y-Factor	869.6	573.4	236.4	1.3	23.2	10.1	7.0	6.3	0.7	3.9	2.9	1.8	0.4	0.2	1.6

Estimated Rate Impacts (2008-2012)

ESTIMATED 2008-2012 RATE IMPACTS

Rate Class	ADR 2008 [1] T-Service Rate Impact	ADR 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%***						

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 the 2010 Historical Year.

2. The Company notes that the Board’s methodology for determining cost of capital is currently under review via a consultative process. The Company will calculate ROE for 2010 in accordance with the methodology established by the Board.

UPDATE

1. The purpose of this update is to reflect the Board’s revised methodology for determining the Return on Equity, as a result of the Board’s consultative process EB-2009-0084.

2. In the Final written comments of October 2009, the Company articulated the following:

> In its notice to stakeholders dated October 5, 2009, the Board indicated that it anticipates that any changes to its policy made as a result of this review will apply to the setting of rates for the 2010 rate year. During 2010, Enbridge will be in the third year of a five year Incentive Regulation plan that was the subject of a Settlement Agreement approved by the Board in EB-2007-0615. While it was not the intention of Enbridge to give up the right to request a reconsideration of ROE during the term of the IR plan, Enbridge has not sought to reopen either the plan or the Settlement Agreement and has not made any request for relief that would trigger a reopening.

Witnesses: J. Denomy
M. Lister

Enbridge nevertheless endorses the approval by the Board of returns that meet the Fair Return Standard and that will apply in the setting of 2010 rates for appropriate utilities, as determined by the Board. At a minimum for Enbridge, any Board-approved ROE will be effective for the purposes of the Earnings Sharing Mechanism ("ESM") described in the EB-2007-0615 Settlement Agreement, inasmuch as the Settlement Agreement provides that the ESM calculation will be based on the regulatory rules prescribed by the Board from time to time.

3. Specifically, with respect to the calculation of the ESM, at Section 10.1, the Settlement Agreement states,

   (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

4. The Board has determined that the appropriate ROE for Ontario's utilities for 2010 is 9.75%, based on a September 2009 Long Canada Bond forecast of 4.25%, and an equity risk premium of 5.50%.

5. Therefore, the threshold for Earnings Sharing purposes will be 10.75% (9.75% + 1.00%).

Witnesses: J. Denomy
M. Lister