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P.O. Box 650
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M1K 5E3

Bonnie Jean Adams
Regualtory Coordinator, Regulatory Affairs
Tel 416-495-5499
Fax 416-495-6072
Email: EGDRegulatoryProceedings@enbridge.com

October 28, 2010

VIA RESS, EMAIL and COURIER

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

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge")
2011 Rate Adjustment Application
Ontario Energy Board ("Board") File Number EB-2010-0146

In addition to the evidence filed on October 1, 2010 for the above noted proceeding, enclosed please find the following updated exhibit:

- Exhibit E, Tab 3, Schedule 1

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

Two paper copies being forwarded to the Board via courier.

Please contact the undersigned if you have any questions.

Yours truly,

Bonnie Jean Adams

Bonnie Jean Adams
Regulatory Coordinator, Regulatory Affairs

cc: Mr. F. Cass, Aird & Berlis LLP (via email and courier)
All Interested Parties EB-2009-0172 (via email)

A – ADMINISTRATIVE

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
	5	1	Draft Issues List	R. Bourke

B – 2011 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	2011 Rate Adjustment Summary	R. Bourke
		2	2011 Revenue per Customer Cap Determination	K. Culbert A. Kacicnik R. Lei D. Small
		3	Inflation Factor	I. McLeod
		4	Customer Additions	F. Ahmad I. McLeod
		5	Gas Volume Budget	R. Lei
		6	Budget Degree Days	I. McLeod H. Sayyan
		7	Average Use Forecasting Model and Economic Assumptions	I. McLeod H. Sayyan
	2	1	Y Factor Power Generation Projects	S. Murray J. Sim
		2	Y Factor DSM Program	K. Culbert

EXHIBIT LIST

B – 2011 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION

EXHIBIT LIST

B – 2011 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION

Exhibit	Tab	Schedule	Contents	Witness(es)
B	5	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	Update of Sharing of Tax Change Savings Forecast Amounts	K. Culbert

D – 2009 ACTUAL RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	2009 Historical Year Review EB-2010-0042	K. Culbert
		2	2009 Service Quality Requirements	T. Ferguson K. Lakatos-Hayward

E – REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
E	1	1	Settlement Agreement – EB-2007-0615 dated February 4, 2008	R. Bourke
	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	I. McLeod S. Murray

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.

A P P L I C A T I O N

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

2. Enbridge hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 36 of the Ontario Energy Board Act, 1998, as amended (the "Act") for an Order or Orders approving or fixing just and reasonable rates for the sale, distribution, transmission and storage of gas commencing January 1, 2011.

3. As of January 1, 2011, Enbridge will be entering the fourth year of a five year Incentive Regulation plan approved by the Board in EB-2007-0615. The Board-approved Settlement Agreement in EB-2007-0615 (the "Settlement Agreement") establishes a revenue per customer cap framework for Enbridge's rates over the period from 2008 to 2012. Specifically, the Settlement Agreement provides that the Company's distribution revenue, in each year of the period January 1, 2008 through December 31, 2012 shall be determined by the application of a Distribution Revenue Requirement Per Customer Formula (the "Adjustment Formula").

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

i. the application of the Adjustment Formula for the year commencing January 1, 2011; and

ii. the continuation of deferral and variance accounts for 2011 and the determination of all other issues that bear upon the Board's approval or fixing of just and reasonable rates for the sale, distribution, transmission and storage of gas by Enbridge for the year commencing January 1, 2011.

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

6. As a result of this Application, average rate increases will be approximately 1.0% 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 1.0% or about $6 annually. As required by the Settlement Agreement, Enbridge's filing in support of the Application will include detailed evidence explaining the rate changes.

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

8. The evidence in support of this Application will be filed by October 1, 2010. Enbridge respectfully requests that the Board establish a process for this Application that is consistent with the timeline approved in the Decision and Order in Phase 2 of EB-2008-0219.

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

The Applicant:

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

Address for personal service:	500 Consumers Road Willowdale, Ontario M2J 1P8
Mailing address:	P. O. Box 650 Scarborough, Ontario M1K 5E3
Telephone:	416-495-5499 or 1-888-659-0685
Fax:	416-495-6072
Email:	EGDRegulatoryProceedings@enbridge.com

The Applicant's counsel:

Mr. Fred D. Cass
Aird & Berlis LLP

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

DATED: September 1, 2010 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: ______________________
Norm Ryckman,
Director Regulatory Affairs

APPROVALS REQUESTED

1. The Company has filed evidence in support of its determination of the 2011 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 2011 rate adjustment are located in the "B" series of exhibits.

2. The rate schedules filed at Exhibit B, Tab 3, Schedule 2 are the culmination of the 2011 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, 2011.

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

4. The methods, models, and processes used in the determination of the individual elements and sub-elements that are integral to the index of historical inflation or the forecast of degree days, or volumes or customer additions, or Y factors have been examined and subsequently approved by the Board in the Company's recent rate proceedings. There are requests for Y factors included with this application which are extensions or true-ups of Y-factors as previously examined and approved by the Board during the first three years, 2008 to 2010, of Enbridge's IR model.

Witness: R. Bourke

5. Inherent in the request to approve the 2011 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, Tab 1, Schedule 4);
   ii) Gas Volume Budget (Exhibit B, Tab 1, Schedule 5);
   iii) Forecast of Degree Days (Exhibit B, Tab 1, Schedule 6);
   iv) Forecast of Average Use (Exhibit B, Tab 1, Schedule 7);
   v) Y Factor Power Generation Projects (Exhibit B, Tab 2, Schedule 1);
   vi) Y Factor DSM Program (Exhibit B, Tab 2, Schedule 2);
   vii) Y Factor – Gas Cost and Carrying Costs (Exhibit B, Tab 2, Schedule 4);
   viii) Y Factor - CIS/Customer Care Costs (Exhibit B, Tab 2, Schedule 3); and
   ix) The 2010 adjustment using the Tax Rate and Rule Change VA (“TRRCVA” Exhibit C, Tab 1, Schedule 2).

6. The Company is also requesting that the Board approve for the 2011 Test Year, the deferral and variance accounts as shown in the evidence in this proceeding at Exhibit C, Tab 1, Schedule 1.

CURRICULUM VITAE OF
FAHEEM AHMAD

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

CURRICULUM VITAE OF
ROBERT ALAN BOURKE, CMA

Experience: Enbridge Gas Distribution Inc.

Manager Regulatory Proceedings
2004

Manager Budget and Administration – Operations
2003

Manager Regulatory Accounting
1998

Senior Analyst Regulatory Accounting
1995

Supervisor Revenue and Gas Cost
1992

Centra Gas (Ontario) Inc.

Supervisor, Budget Administration
1992

Thornhill Glass & Mirror Inc.

Controller
1988

The Consumer Gas Company Limited

Manager System Customer Billing
1987

Management Trainee
1986

Supervisor Income and Cash Budget
1982

Asst. Supervisor Income and Cash Budget
1980

Education: Certified Management Accountant (CMA), 1981

Memberships: The Society of Management Accountants Ontario

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

CURRICULUM VITAE OF
JACKIE E. COLLIER

Experience:	Enbridge Gas Distribution Inc.
	Manager, Rate Design 2003
	Manager, Rate Research 2000
	Senior Rate Research Analyst 1996
	Centra Gas Ontario Inc.
	Manager, Rate Design 1995
	Supervisor, Cost of Service Studies 1990
Education:	Bachelor of Business Management Ryerson Polytechnical Institute, 1988
Appearances:	(Ontario Energy Board) EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2008-0106 EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2003-0048 RP-2002-0133 RP-2001-0032 RP-2000-0040 EBRO 489 EBRO 474-B, 483,484 EBRO 474-A EBRO 474 EBRO 471
	(Régie de l'énergie/Régie du gaz naturel) R-3692-2009 R-3665-2008 R-3637-2007 R-3621-2006 R-2587-2005 R-3537-2004 R-3464-2001 R-3446-2000

CURRICULUM VITAE OF
KEVIN CULBERT

Experience:	Enbridge Gas Distribution Inc.
	Manager, Regulatory Accounting Current
	Manager, Regulatory Accounting 2003
	Senior Analyst, Regulatory Accounting 1998
	Analyst, Regulatory Accounting 1991
	Assistant Analyst, Regulatory Accounting 1989
	Budgets – Capital Clerk, Budget Department 1987
	Accounting Trainee, Financial Reporting 1984
Education:	CMA (3rd level) Seneca College 1987-89 (business/accounting)
Appearances:	(Ontario Energy Board) EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2008-0104/EB-2008-0408 EB-2007-0615 EB-2006-0034 EB-2005-0001 RP-2003-0203

CURRICULUM VITAE OF
TANYA M. FERGUSON

Experience:	Enbridge Gas Distribution Inc.
	Manager Customer Care Operations, Customer Care 2010
	Manager Customer Care Financial Administration, Customer Care 2006
	Manager Special Projects, Customer Care 2005
	Senior Analyst, Planning and Projects 2002
	Supervisor, Internal Reporting 2000
	Enbridge Services Inc.
	Financial Analyst, Financial Reporting 1999
	Enbridge Gas Distribution Inc.
	Corporate Accountant, Financial Reporting 1998
	Audit Assistant, Audit Services 1998
	Accounting Trainee, Financial Reporting 1997
Education:	Masters of Business Administration York University, 2002
	Certified Management Accountant Society of Management Accountants, 2000
	Bachelor of Commerce (Honours) University of Windsor, 1996
Memberships:	Certified Management Accountant Society of Management Accountants
Appearances:	(Ontario Energy Board) EB-2005-0001
	(Ontario Energy Board) RP-2003-0203

CURRICULUM VITAE OF
ANTON KACICNIK

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Research & Design
2007

Manager, Cost Allocation
2003

Program Manager, Opportunity Development
1999

Project Supervisor, Technology & Development
1996

Pipeline Inspector, Construction & Maintenance
1993

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

Memberships: Professional Engineers of Ontario

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

(RÉGIE DE L'ÉNERGIE)
R-3621-2006
R-3587-2006
R-3537-2004

Memberships:	Society of Management Accountants of Ontario
Appearances:	(Ontario Energy Board) RP-2002-0133 RP-2001-0032

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
RAYMOND LEI

Experience: Enbridge Gas Distribution Inc.

Manager, Budgets and Business Support
2010

Manager, Corporate Budgets and Analysis
2007

Manager, Financial Analysis
2007

Senior Analyst, Planning and Projects
2005

Rogers Wireless Inc.

Senior Analyst, Budgets and Forecast
2001

Royal LePage Relocation Services Ltd.

Financial Analyst
2000

Kodak (China) Limited

Business Analyst
1995

Education: Certified General Accountant
Certified General Accountants of Ontario, 2005

Master of Business Administration
York University, 2000

Bachelor of Arts in Commerce and Economics
Sichuan University, China

Memberships: Certified General Accountant, Ontario

Appearances: (Ontario Energy Board)
EB-2009-0172

CURRICULUM VITAE OF
IAN McLEOD

Experience:	Enbridge Gas Distribution Inc.
	Advisor, Economic & Market Analysis 2010
	Senior Market Analyst, Economic & Market Analysis 2009
	Market Analyst, Economic & Market Analysis 2006
Education:	Master of Arts, Business Economics (2006) Wilfrid Laurier University
	Bachelor of Arts (Honours), Economics and Business Administration (2004) Wilfrid Laurier University
Memberships:	Canadian Association of Business Economics – Toronto Chapter
Appearances:	(Régie de l'énergie) R-3724-2010

CURRICULUM VITAE OF
STUART MURRAY

Experience:	Enbridge Gas Distribution Inc.
	Manager, Investment Review and Economic Analysis 2010
	Manager, Investment Review and Customer Growth 2008
	Manager, Financial Assessment 2006
	Pitney Bowes Canada
	Project Manager, Enterprise Program Office 2003
	Finance Manager, Service Operations 2001
	Finance Manager, New Business Development 2000
	Canadian Tire Corporation
	Business Analyst, Marketing Finance 1997
	Financial Analyst, Corporate Planning 1996
Education:	Master of Business Administration McMaster University, 1995
	B.A. Economics, Administrative & Commercial Studies University of Western Ontario – 1993
Membership:	None
Appearances:	(Ontario Energy Board) EB-2006-0034

CURRICULUM VITAE OF
HULYA SAYYAN

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

CURRICULUM VITAE OF
JEFFREY SIM

Experience: Enbridge Gas Distribution Inc.

Manager, Strategic Accounts, Direct Purchase
2010

Manager, Market Development, Distributed Energy
2006

Business Manager, Distributed Energy
2002

Supervisor, Gas Supply Planning
1997

Gas Controller, Gas Control
1988

Technologist, Laboratory Services
1983

Technician, Laboratory Services
1978

Education: Undergraduate, B. Sc., University of Toronto, 1976

Memberships: Association of Power Producers of Ontario
Board Member, Fuel Cells Canada, 2005-2008

Appearances: (Ontario Energy Board)
None previous.

CURRICULUM VITAE OF
DONALD R. SMALL

Experience:	Enbridge Gas Distribution Inc.
	Manager , Gas Costs and Budget 2010
	Manager, Gas Cost Knowledge Centre 2003
	Manager, Gas Costs and Budget 1989
	Co-ordinator, Gas Costs 1984
	Financial Statement Accountant 1980
	Chief Clerk, Financial Statements 1979
	Advanced Accounting Trainee 1978
Education:	Business Administration Diploma Ryerson Polytechnical Institute, 1978
Appearances:	(Ontario Energy Board) EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2008-0106 EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2003-0048 RP-2002-0133 RP-2001-0032 RP-2000-0040 RP-1999-0001 EBRO 497 EBRO 495 EBRO 492 EBRO 490 EBRO 487 EBRO 485 EBRO 479 EBRO 473 EBRO 465

CURRICULUM VITAE OF
MARGARITA SUAREZ-SHARMA

Experience: Enbridge Gas Distribution Inc.

Manager, Cost Allocation
2008

Manager, DSM Reporting & Analysis
2005

Analyst, Rate Design
2004

Senior Analyst, DSM Planning and Evaluation
2002

Senior Economic Analyst, Economic & Financial Studies
1998

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-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106

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

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

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

10) Is the adjustment calculated for the 2010 Tax Rate and Rule Change Variance Account (“TRRCVA”) appropriate?

11) 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 approved for use during the IR period and as updated and approved in the Company's 2010 rate proceeding (EB-2009-0172) save and except for the discontinuation of the Change in Purchased Gas Variance Disposition Methodology DA ("CPGVDMDA")?

12) How should the new rates be implemented?

2010 RATE ADJUSTMENT SUMMARY

1. The Company is proposing to adjust its rates for the 2011 fiscal year within the parameters established in the Board Approved Incentive Regulation ("IR") formula (EB-2007-0615 dated 4-Feb-2008). The Settlement Agreement from that proceeding has been filed at Exhibit E, Tab 1, Schedule 1 for reference in this proceeding.

2. The Company anticipates an approach which will adjust rates to be implemented effective in January 2011 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 amounts included in the proposed 2011 rate adjustment have been filed primarily in the "B" series of exhibits. The 2011 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. The proposed rate schedules are found at Exhibit B, Tab 3, Schedule 2, with the balance of the schedules filed in Tab 3 representing material that has been submitted in support of the development of the rate schedules.

4. The 2009 historical year information was filed, reviewed and adjudicated in the EB-2010-0042 Earnings Sharing Mechanism ("ESM") proceeding. That material is available (1) on the Board's eFiling Services website under docket EB-2010-0042 or (2) in electronic format by request to the Regulatory department staff at Enbridge.

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

Witness: R. Bourke

B – 2011 RATE ADJUSTMENT CALCULATION AND SUPPORTING INFORMATION

2011 REVENUE PER CUSTOMER CAP, DISTRIBUTION AND TOTAL REVENUE DETERMINATION

Row		Col. 1 2011
1.	2010 Total Approved Revenue	2,434.3
2.	Gas Costs to operations (at Oct. 1, 2009 ref. price)	1,453.5
3.	2010 Approved Distribution Revenue	980.8
4.	2010 Gas in storage related carrying costs (at Oct. 1, 2009 ref. price)	(36.7)
5.	DSM 2010 amount	(26.7)
6.	CIS / Cust. Care 2010 amount	(95.7)
7.	Power generation projects 2010 amount	(3.6)
8.	Distribution Revenue Sub-total	818.1
9.	Ratepayer 50% share of 2011 incremental tax amounts	(5.3)
10.	Distribution Revenue base (subject to the escalation formula, $millions)	812.8
11.	Average Number of Customers (Beginning)	1,931,528
12.	Distribution Revenue per Customer 2011 (Beginning)	$ 420.81
13.	GDP IPI FDD	0.72%
14.	Inflation Coefficient (allowed % of GDP IPI FDD)	50.00%
15.	Escalation Factor, 100 plus (GDP IPI FDD multiplied by the inflation coeff.)	100.36%
16.	Distribution Revenue per Customer 2011 (Ending)	$ 422.32
17.	Average Number of Customers (Ending)	1,965,537
18.	Distribution Revenue (resulting from the escalation formula, $millions)	830.09
	Y-Factors	
19.	2011 Gas in storage related carrying costs (at October 1, 2010 ref. price)	30.90
20.	2011 DSM Y-factor amount	26.70
21.	CIS / Customer Care 2011 approved amount	97.40
22.	Power generation projects 2011 amount	3.50
23.	Total 2011 Y-Factors	158.50
24.	Total 2011 Distribution Revenues	988.59
25.	2011 Gas Costs to operations (at October 1, 2010 ref. price)	1,416.30
26.	2011 Total Revenue	2,404.89

2011 DISTRIBUTION REVENUE PER CUSTOMER CAP
DISTRIBUTION AND TOTAL REVENUE DETERMINATION (2011)

Enbridge Gas Distribution's ("Enbridge") revenue per customer cap calculation for 2011 has been determined through the continued use and updating of various components or elements of the Incentive Regulation Model and revenue determination formula that was approved by the Board in EGD's 2008 rate proceeding, EB-2007-0615.

As shown on page 1 of this schedule, the 2011 total revenue amount to be collected through rates is calculated through the completion of the process explained below. Formula amounts and percentage referred to below are all found in Column 1 of page 1 of this exhibit.

Process

1. Row 1, $2,434.3 million, the starting point of the calculation, is the 2010 Total Board Approved revenue as per the EB-2009-0172 Final Rate Order, Appendix A, page 1, Column 3, Line 30.

2. Row 2, eliminates the gas cost of $1,453.5 million embedded within that total approved revenue to arrive at Row 3, the 2010 Board Approved distribution revenue of $980.8 million. Removal of this gas cost is necessary as it was based on prices underpinning the October 1, 2009 gas cost reference price of $236.950 /$10^3m^3$ and was relative to 2010 approved volumes[1]. The elimination is required in order to establish a base distribution revenue upon which the IR escalation formula can be applied exclusive of gas costs. A 2011 forecast gas cost, outside of the IR escalation formula, is included into the 2011 total revenue at Row 25, and is explained later in this evidence.

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

Witnesses: K. Culbert
A. Kacicnik
R. Lei
D. Small

3. Row 3 shows the 2010 Board Approved distribution revenue of $980.8 million, to which the following further adjustments are required in order to calculate a distribution revenue upon which the IR escalation formula can be applied within the context of Enbridge's approved revenue per customer cap model.

4. Row 4 eliminates $36.7 million, which is the embedded carrying cost on gas in storage and working cash related to gas costs in the 2010 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 2010 Board Approved distribution revenue which was based on 2010 approved volumes and prices underpinning the October 1, 2009 gas cost reference price of \$236.950 /10^3m^3. This elimination establishes a distribution revenue upon which the IR escalation formula can be applied exclusive of carrying costs on 2010 gas in storage and gas cost working cash amounts related to 2010 approved volumes and gas cost prices. A carrying cost on gas in storage and gas cost working cash for 2011, outside of the IR escalation formula, is included in the 2011 total revenue and explained at Row 19 later in this process. Please refer to Exhibit B, Tab 1, Schedule 2, Appendix A.

5. Row 5 removes the 2010 Board Approved DSM operating costs of $26.7 million as established within the EB-2009-0172 Decision. This adjustment is necessary as DSM operating cost budgets are approved in separate proceedings, therefore the base distribution revenue upon which the IR escalation formula can be applied needs to exclude DSM approved amounts. The 2011 DSM operating cost as requested within the EB-2010-0175, Natural Gas DSM Plan proceeding is $26.7 million, and is included in the 2011 total revenue, outside of the IR escalation formula, at Row 20.

Witnesses: K. Culbert
A. Kacicnik
R. Lei
D. Small

6. Row 6 removes the 2010 Board Approved CIS/Customer Care costs of $95.7million (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 IR escalation formula is to be applied should exclude CIS/Customer Care costs. The 2011 Approved CIS/Customer Care costs are included in the 2011 distribution revenue outside of the IR escalation formula and are further outlined at Row 21.

7. Row 7 removes the 2010 Board Approved power generation related Y-factor revenue requirement amount of $3.6 million from the base subject to escalation. The inclusion of an updated 2011 revenue requirement amount of $3.5 million is shown at Row 22. Power generation project cost treatment was approved to be handled outside of the escalation portion of the IR formula.

8. Row 8 shows a distribution revenue sub-total of $818.1 million, inclusive of all of the above noted adjustments. This is the amount of the Board Approved formula portion of 2010 rates as shown at Appendix A, page 1, Column 3, Row 18 of the EB-2009-0172 Rate Order.

9. Row 9 incorporates an incremental reduction to base rates of $5.3 million, which is the 2011 ratepayer amount relating to incremental tax rate and rule change expectations, 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 update does not affect the 2011 or beyond IR calculations, is purely as a result of tax rule changes which affected the 2009 and 2010 fiscal years, and is proposed to be dealt with through the existing Tax Rate and Rule

Change Variance Account. The Company has filed evidence explaining the reason for the proposed update at Exhibit C, Tab 1, Schedule 2.

10. Row 10 shows the total base distribution revenue of $812.8 million, upon which the Approved IR escalation formula can be applied.

11. Row 11 provides the 2010 Board Approved average number of customers of 1,931,528 (from EB-2009-0172, Rate Order, Appendix A, page 1, Column 3, Row 17) which is used in the next step of this process to calculate the base distribution revenue/customer before 2011 Y factor amounts.

12. Row 12 is the base distribution revenue per customer of $420.81, which is derived by dividing the Row 10 base distribution revenue of $812.8 million by the 2010 approved average customers of 1,931,528.

13. Row 13, 0.72%, is the updated Canadian Gross Domestic Product Implicit Price Index for Final Domestic Demand ("GDP IPI FDD") inflation factor component of the EB-2007-0615 Board Approved IR escalation formula which is found in evidence at Exhibit B, Tab 1, Schedule 3.

14. Row 14, 50%, is the 2011 inflation co-efficient component of the IR escalation formula as approved by the Board in the EB-2007-0615 Rate Order, Appendix A, page 1, Column 3, Row 15.

15. Row 15, 100.36% (or a multiplier of 1.0036) is the adjustment factor calculated as 100% plus 0.36% (0.36% is calculated as the GDP IPI FDD inflation factor of 0.72% multiplied by 50%) which is required in the next step to arrive at an escalated average distribution revenue per customer amount.

Witnesses: K. Culbert
A. Kacicnik
R. Lei
D. Small

16. Row 16, $422.32, is the 2011 distribution revenue per customer which is calculated by multiplying the distribution revenue per customer at Row 12 of $420.81 by the adjustment factor of 100.36% or a multiplier of 1.0036.

17. Row 17 provides the 2011 forecast average number of customers of 1,965,537 which is found in evidence at Exhibit B, Tab 1, Schedule 5.

18. Row 18, $830.09 million, is the 2011 distribution revenue which is calculated by multiplying the 2011 distribution revenue per customer amount of $422.32 by the forecast 2011 average number of customers of 1,965,537. This distribution revenue is further adjusted in Rows 19 through 25, to arrive at a 2011 total revenue for which 2011 rates are developed.

19. Row 19 increases the $830.09 distribution revenue by $30.9 million for carrying costs on 2011 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 2010 approved distribution revenue need to be removed in order to apply the IR escalation formula, the 2011 carrying cost on gas in storage and gas cost working cash related to 2011 forecast volumes and prices underpinning the October 1, 2010 gas cost reference price need to be included in the 2011 total revenue. This type of adjustment is required in order to develop rates which incorporate the upcoming 2011 volumetric forecasts and changes in approved gas prices, (Refer to Exhibit B, Tab 1, Schedule 2, Appendix A) and in order to ensure a proper baseline to which Enbridge's current approved rates which contain the October 1, 2010 approved gas cost reference price and associated carrying cost impacts can be compared.

Witnesses: K. Culbert
A. Kacicnik
R. Lei
D. Small

20. Row 20 increases the $830.09 million distribution revenue by $26.7 million, which is the Company's approved 2011 DSM operating cost budget, found in evidence in EB-2010-0175, Exhibit B, Tab 1, Schedule 1. The addition of 2011 DSM costs, to 2011 total revenue, is required as 2010 DSM costs were previously removed as explained in the narrative for Row 5.

21. Row 21 increases the $830.09 million distribution revenue by $97.4 million, the 2011 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, $3.5 million, represents the 2011 revenue requirement associated with Y-factor capital expenditures for power generation projects which were approved by the Board for inclusion within Enbridge's IR formula and determination. Evidence can be found at Exhibit B, Tab 2, Schedule 1, Appendix A.

23. Row 23, $158.5 million, is the sum of Rows 19 through 22, total 2011 Y-factors.

24. Row 24, $988.59 million, is Enbridge's total 2011 distribution revenue before gas costs which 2011 rates will be designed to recover.

25. Row 25, $1,416.3 million, is the 2011 forecast gas cost required to be added to the 2011 distribution revenue to establish 2011 total required revenue. The $1,416.3 million replaces the previously removed 2010 gas cost value embedded within the starting 2010 Total Board Approved revenue as explained in the narrative for Row 2. Evidence can be found at Exhibits B, Tab 4, Schedules 1 and 2.

Witnesses: K. Culbert
A. Kacicnik
R. Lei
D. Small

26. Row 26, $2,404.89 million, is the 2011 total revenue arrived at and to be used to design rates, following the application of the sum of all of the elements of the approved IR escalation formula. The 2011 rates will be designed to recover this entire amount based on the forecast of 2011 volumes associated with the formula.

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

Line No.		Exhibit Reference	Col.2	Col.3
		Col.1		($000)
		EB-2010-0146	(10^3m^3)	
1.	Average gas in storage volume & value	Exhibit B.T6.S2.pg.4, line 14	1 157 979.4	306,558.7
2.	Gas cost working cash allowance			
2.1	a) Purchase cost of gas		$1,489,087.8	
2.2	b) Net lag-days calculated	EB-2010-0258,Q4-3.T2.S2.line 3.2	5.8	
2.3	c) Dollar days		8,636,709.2	
2.4	d) Number of operating days		365	23,662.2
3.	Rate Base value			330,220.9
4.	Gross return component	(See page 3 of this schedule)		9.36%
5.	Carrying cost requirement			30,908.7

2010 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-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

Calculation of the Gross Rate of Return on Rate Base

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

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

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

2011 Forecast Gas in Storage
In Rate Base and its Associated
<u>Gross Carrying Cost</u>

Line No.		Col.1 Exhibit Reference	Col.2	Col.3
				($000)
		EB-2010-0146	(10^3m^3)	
1.	Average gas in storage volume & value	Exhibit B.T6.S2.pg.4, line 14	1 157 979.4	306,558.7
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2010 Forecast Gas in Storage
In Rate Base and its Associated
<u>Gross Carrying Cost</u>

Line No.		Col.1 Exhibit Reference	Col.2	Col.3 ($000)
		EB-2009-0172	(10^3m^3)	
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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

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 IR formula. The Company has calculated the inflation factor for 2011 using the Canadian Gross Domestic Product Implicit Price Index for Final Domestic Demand ("GDP IPI FDD").

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

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

where, for example,

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

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

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

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

4. Table 1 outlines the calculation of the inflation factor for 2011. 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 2011 is 0.72%.

Table 1 - Inflation Factor
Calculation of Inflation Factor

Col. 1	*Col. 2*	*Col. 3*
Quarter	Index Value	Annualized Growth Rate
2007 Q4	110.50	
2008 Q1	111.30	
2008 Q2	112.50	
2008 Q3	113.70	
2008 Q4	114.20	
2009 Q1	114.30	
2009 Q2	114.30	
2009 Q3	114.20	0.44%
2009 Q4	114.90	0.61%
2010 Q1	115.30	0.87%
2010 Q2	115.40	0.96%
Average (Rounded to 2 decimal places)		0.72%

CUSTOMER ADDITIONS

1. The purpose of this evidence is to provide the Company's forecast of customer additions for the Company's 2011 Test Year. The Company is forecasting 36,237 customer additions for 2011. This represents an increase of 3,858 customer additions relative to the 2010 Board approved forecast of 32,379 customer additions.

2. The customer additions forecast for 2011 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 proven 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 begun to recover since the second half of 2009. This recovery follows four consecutive quarters of declines from the third quarter of 2008 to the second quarter of 2009. Real output in the Ontario economy has increased for three consecutive quarters beginning in the third quarter of 2009. In the first quarter of 2010, Ontario real gross domestic product increased, quarter over quarter, by 1.5% or 6.2% annualized. This increase in economic output can be attributed to a variety of factors including the relative financial market stability in Canada and the end to the recession in the U.S., Canada and abroad which has resulted in increasing government, consumer and business spending. Manufacturing, particularly the automotive sector, and exports in general, have registered positive growth rates since the third quarter of 2009. As a result of the

increase in economic activity, the number of individuals employed has increased noticeably resulting in lower unemployment rates and higher disposable incomes. Projections for real GDP growth over the next two years for Ontario are on average higher than the growth rates seen for the past five years. Table 1 contains a summary of the Company's Economic Outlook Spring 2010. Detailed tables outlining the Economic Outlook can be found at Exhibit B, Tab 1, Schedule 7, pages 21 to 24.

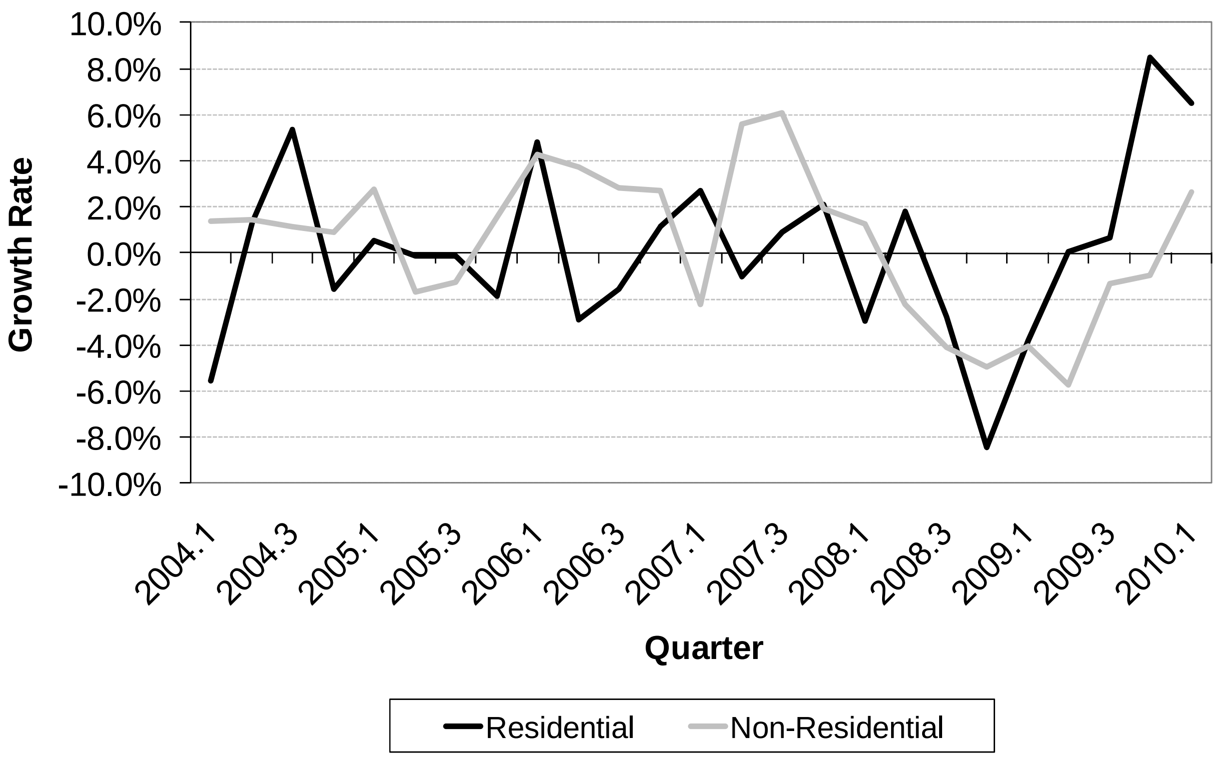
Table 1
Economic Outlook Summary

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Variable	2005	2006	2007	2008	2009	2010 Forecast	2011 Forecast
ONTARIO REAL GDP (% CHANGE)	2.8	2.4	2.3	-0.5	-3.4	3.2	3.2
MORTGAGE RATE 5 YEAR TERM (%)	5.99	6.66	7.07	7.06	5.63	6.30	7.41
ONTARIO HOUSING STARTS (000's)	78.8	73.4	68.1	75.1	50.4	61.5	63.2
CENTRAL REGION HOUSING STARTS (000's)	43.0	38.8	35.7	42.4	25.8	32.6	34.6
EASTERN REGION HOUSING STARTS (000's)	5.2	6.1	6.8	7.2	6.0	7.0	7.3
NIAGARA REGION HOUSING STARTS (000's)	1.5	1.4	1.3	1.3	1.0	1.3	1.3
FRANCHISE AREA HOUSING STARTS (000's)	49.7	46.4	43.8	50.8	32.7	40.8	43.2

4. Commensurate with the increase of overall economic growth, Ontario real gross fixed capital formation in both residential and non-residential construction has also increased. With these trends expected to continue throughout the remainder of 2010 and into 2011 both housing starts and the construction of new commercial and industrial structures is expected to rise. Based on the expectation that 2011 is expected to be the second year of recovery following the 2009 recession, investment in new housing and commercial/industrial buildings is expected to continue its ascent as the economic recovery continues to bolster consumer confidence and the labour market continues to improve. Figure 1 on page 3, shows that the growth rate in real business fixed investment for both residential and non-residential structures has trended higher over the past few quarters.

Witnesses: F. Ahmad
I. McLeod

Figure 1: Ontario Real Gross Fixed Capital Formation



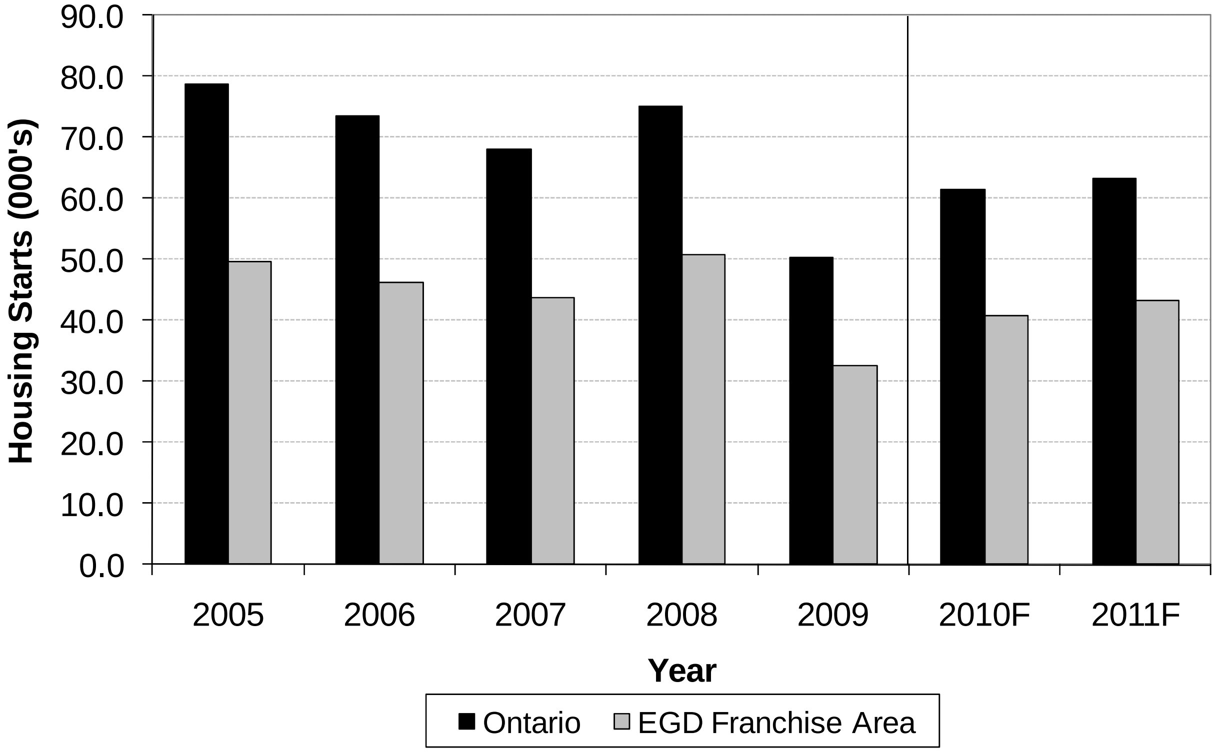
5. The most recent peak in Ontario housing starts occurred in 2003. At that point in time the target for the overnight rate set by the Bank of Canada was near historical lows, averaging 2.94% for the year. Recently the Bank of Canada had aggressively reduced interest rates in an attempt to free up credit and smooth the impact of the global economic slowdown on Canada's economy. A new historic low was set in 2009 as the Bank of Canada dropped the target for the overnight rate to a mere 25 basis points and 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, but given the expectation of a rising overnight rate target mortgage rates should begin to rise, albeit to rates which remain relatively low by historical standards. Relatively low interest rates translate into comparatively low financing costs for

houses and commercial structures. Consequently relatively low carrying costs should at least maintain or put upward pressure on housing starts and business construction. Table 1 on page 2, provides the Company's outlook for mortgage rates.

Housing Market

6. Over the past 5 years housing starts in Ontario and the Company's franchise area have trended down since reaching a peak in 2003. With the beginning of a new recovery period in the Ontario economy, the Company expects this trend to reverse course slowly during 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 on page 2, shows the Company's forecast of housing starts for 2010 and 2011. With the combination of relatively lower interest rates and rising economic activity, the Company expects housing starts to increase in 2010, largely as a result of increasing consumer confidence as the unemployment rate declines. Expectations are for housing starts to also increase through 2011 as the Ontario economy maintains its upward trajectory, with rising employment and economic output. Figure 2 on page 5, shows the general downward trend in housing starts for Ontario and the Company's franchise area since 2005. The increase in 2008 is attributable to a surge in apartment housing starts in Toronto.

Figure 2: Housing Start Trends



7. To stem the risk of speculative buying and discouraging homeowners from taking on too much debt, the Department of Finance introduced some changes to its mortgage insurance guarantee framework. Specific amendments include increasing borrowers' standards from a three-year fixed-rate mortgage to a five-year fixed mortgage. As well, the down payment borrowers are to pay for a property where they will not be living has increased to 20% of the purchase price. Finally, homeowners are now allowed to only borrow against 90% of the value of their property, versus the previous level of 95%. These measures, in addition to the amendments announced in 2008, are designed to have a stabilizing effect on the housing market.

Witnesses: F. Ahmad
I. McLeod

8. 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 4.9 in 2008 and 6.4 in 2009. Dramatic increases in the number of existing homes listed for sale has offered home buyers more options and increased competition for developers of new homes. However, average resale home prices rose 5.3% from 2008 to 2009 while new home prices were flat over the same time period. This differential in price growth rates indicates a loss in competitiveness of resale homes to new homes which will be supportive of new construction to satisfy housing demand.

Residential Customer Additions

9. 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 consist 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. However, this trend is expected to reverse course in 2010 and 2011. The Company is forecasting 33,612 residential customer additions for 2011. This forecast is comprised of 27,303 new construction customer additions and 6,309 replacement customer additions.

Apartment Customer Additions

10. Over the second half of 2009 apartment starts in Toronto began to recover modestly. With the end to the economic downturn this trend is expected to continue to rise over the coming years. The Company is forecasting 38 apartment customer additions in 2011. Of this number, 30 are new construction customer additions and 8 are replacement customer additions.

Commercial Customer Additions

11. The economic recovery is expected to keep business investment in commercial non-residential structures consistent. The Company is currently forecasting 2,583 commercial customer additions for 2011. This forecast is comprised of 1,762 new construction customer additions and 821 replacement customer additions.

Industrial Customer Additions

12. Much like the commercial sector, the economic recovery will maintain business investment in non-residential structures for the industrial sector. The manufacturing sector in Ontario is still under pressure from a high Canadian dollar and foreign competition, and will be attempting to generate as much output with as few inputs as possible. The Company is forecasting 4 industrial customer additions for 2011, 3 of which are new construction customer additions and 1 of which is a replacement customer addition.

13. Table 2 on page 8, provides the Company's forecast of customer additions for 2011. In summary, the end of the recession and the expectation of a recovery in housing starts are expected to cause customer additions to rise to a level of 36,237 in 2011. This represents an increase of 3,858 customer additions relative to the Company's 2010 Board approved customer additions forecast.

Table 2
Customer Additions

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Sector	2009 Actual	2010 Board Approved Budget	2011 Forecast
Residential			
New Construction	23,110	22,616	27,303
Replacement	6,385	7,174	6,309
Total	29,495	29,790	33,612
Apartment			
New Construction	66	19	30
Replacement	2	7	8
Total	68	26	38
Commercial			
New Construction	1,899	1,665	1,762
Replacement	621	888	821
Total	2,520	2,553	2,583
Industrial			
New Construction	5	7	3
Replacement	1	3	1
Total	6	10	4
Total Customer Additions	32,089	32,379	36,237

Witnesses: F. Ahmad
I. McLeod

GAS VOLUME BUDGET

1. The purpose of this evidence is to present the 2011 Test Year forecast of volumes and related information. The evidence describes the forecasting methodology and key assumptions used to develop the 2011 volumes for General Service and Large Volume Budgets. The 2011 volume budget incorporates calendar 2009 actual billing consumption for both General Service and Large Volume.

2. A summary of the volumes and customers is provided below. Further rate class detail and explanations 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)

	2009 Board Approved Budget	2009 Actual	2010 Board Approved Budget	2010 Bridge Year Estimate	2011 Budget
General Service Volumes	9 083.2	9 129.2	9 083.5	9 089.9	9 283.4
Contract Volumes	2 316.6	2 205.6	2 008.6	2 061.7	2 022.9
Total Volumes, Gas Sales and Transportation	11 399.8	11 334.8	11 092.1	11 151.6	11 306.3
Customers, Gas Sales and Transportation (Average)	1 906 437	1 887 605	1 931 528	1 935 736	1 965 538

Witness: R. Lei

3. As a consequence of the implementation of the result 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 on page 1, to unbundled rate classes (e.g. Rate 125, Rate 300 Firm) that do not have distribution volumes. Unbundled customers incur monthly contract demand volumes and generate fixed contract demand revenues. Table 2 below presents a summary of these contract demand volumes.

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

	2007 Actual	2008 Actual	2009 Board Approved Budget	2009 Actual	2010 Board Approved Budget	2010 Bridge Year Estimate	2011 Budget
Total Contract Demand Volumes	12.5	40.0	74.2	74.2	82.6	82.1	81.1

General Service Demand Forecast Methodology

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

5. Consistent with previous rate cases, the Company continues to report the results that the models would generate using the actual data and driver variable information to allow parties to compare the results to the prior year's forecast. The average in-sample forecast error for both Rate 1 and Rate 6 regression models is

still less than 1 percent on average during 2001 to 2009 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.

6. Annual econometric models are employed to model and quantify the impact of various driver variables on average use per customer. The forecast incorporated economic assumptions from Economic Outlook, Spring 2010 filed at Exhibit B, Tab 1, Schedule 7. The average use regression models forecast includes 2009 actual billing consumption information.

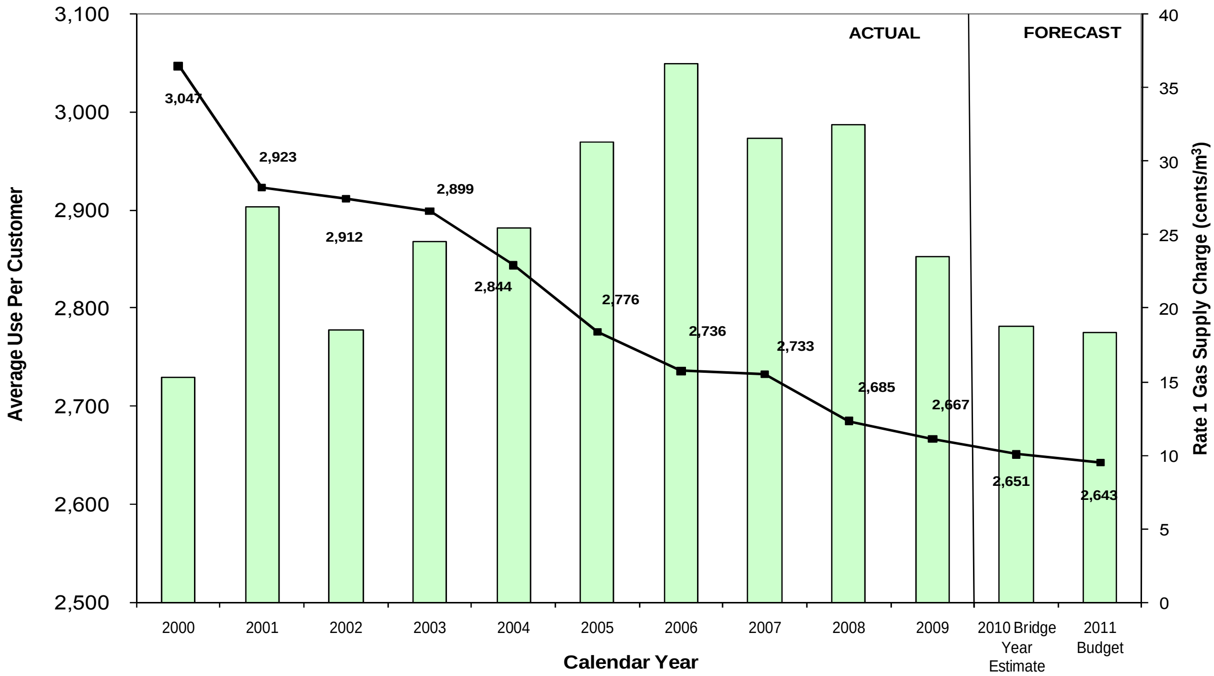
7. The major driver variables in Rate 1 and Rate 6 models are heating degree days, vintage (Rate 1 only), employment, Ontario real gross domestic product, Ontario real gross domestic *product by manufacturing ind*ustry, vacancy rates (Rate 6 only), real energy prices, and time trend. The vintage variable is constructed to reflect the impact of new homes associated with more energy efficient gas equipment over time and enhanced building codes. Gas equipment includes gas furnaces, water heaters, and stoves. The time trend, including the dynamic variable in the regression model, captures the historical actual average trend of the sectoral average use, 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 impacts 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: 2011 Budget

8. The 2011 Budget General Service volumes are 9,283.4 10^6m^3. From 2000 to 2009, normalized residential average use has declined by an average of 38.0 m^3 or

1.4% per year for residential customers. However, during the volatile and high natural gas price period between 2000 and 2006, normalized residential average use decreased by an average of 44 m³ or 1.5% per year for residential customers. Figure 1 below shows the residential average use from 2000 to the 2011 Test Year, on a weather normalized basis, as filed at Appendix A, page 21.

Figure 1
Residentail Normalized Average Use (m³)



9. Residential average use is forecast to continue to decline in 2011 due to reasons that include:

- 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, etc);

- Space heating and water efficiency gains due to ongoing furnace stock turnover and new construction additions with more energy efficient furnaces;
- 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;

These are partially offset by factors such as lower gas prices predicted in 2011 than in 2010.

10. On June 28, 2006, the Government of Ontario introduced a 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. These building code changes established requirements 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. Further building code changes related to energy efficiency phased in during 2009 require near-full-height basement insulation. In 2012, new houses will be required to meet standards in accordance with the national guideline, EnerGuide 80.[1]

11. The current volumetric forecast has not incorporated the potential adverse impact of further self-imposed energy conservation activities undertaken by customers due to the implementation of the Harmonized Sales Tax (HST) in July 2010. As a

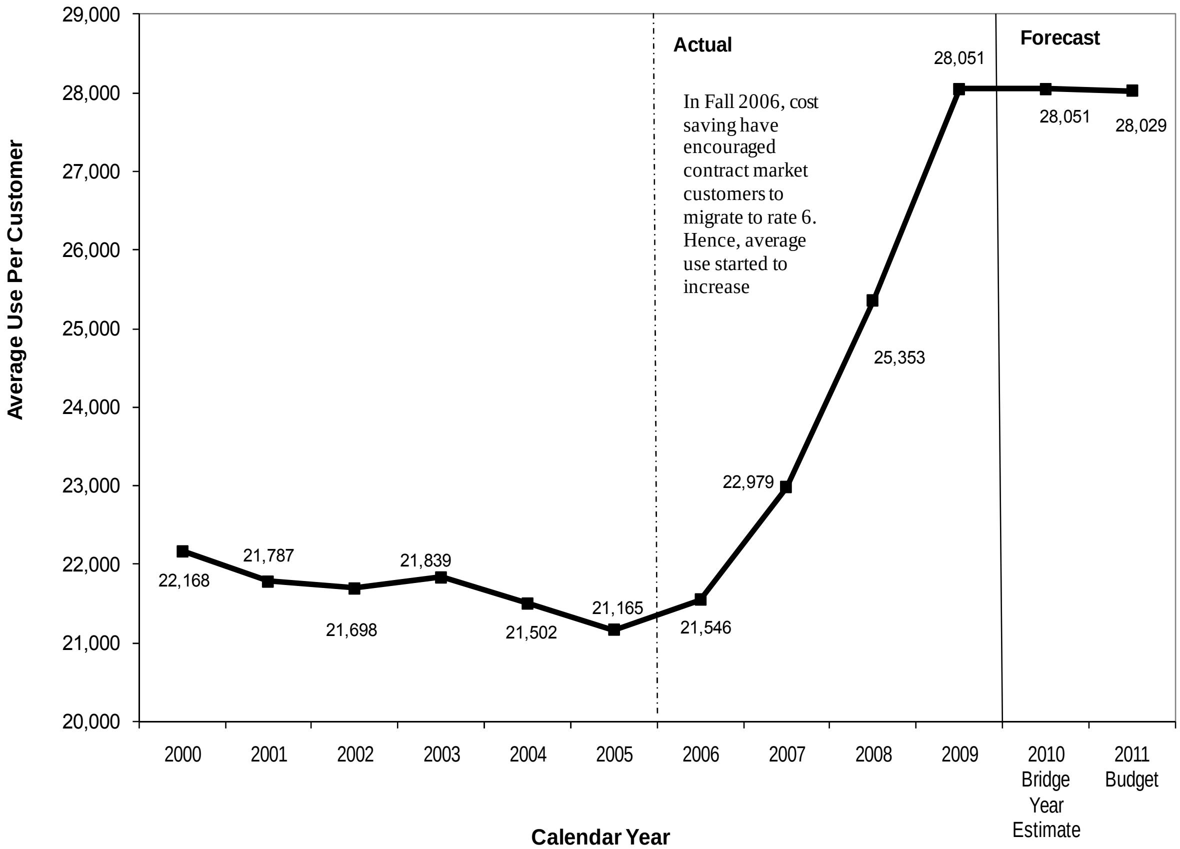
[1] Please refer to the Ministry of Municipal Affairs and Housing web site for further technical information, http://www.mah.gov.on.ca/Page681.aspx.

result of the HST, home energy costs will increase by 8 per cent. This may 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.

12. Rate 6 is comprised of the apartment, commercial, and industrial sectors. From 2000 to 2009, normalized Rate 6 average use has increased by an average of 588 m^3 or 2.7% per year. The increase from 2006 to 2009 actual usage is largely attributable to the rate switching from contract customers to general service, which began in the fall of 2006. Rate switching accelerated as indicated in the response to an Undertaking at EB-2006-0034, Exhibit J4.10 and 2008 Gas Volume Budget Evidence at EB-2007-0615, Exhibit C, Tab 2, Schedule 2. Rate design changes required Rates 100 and 145 to pay contract demand charges effective April 1, 2007, thus Rate 6 became more attractive to some contract market customers.

13. Figure 2 on the following page, shows the Rate 6 average use from 2000 to the 2011 Test Year Budget on a Test Year weather normalized basis, as filed at Appendix A, page 21. During the high and volatile natural gas price period between 2001 and 2006, normalized Rate 6 average use decreased by an average of 103.0 m^3 or 0.5% per year. Absent any further change in rate design, it is expected that rate switching between general service and the contract market will stabilize in 2011, and consequently, so will Rate 6 average use.

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



14. Economic conditions and rate switching have always played a significant role in Rate 6 average use. Rate 6 customers often switch between rate classes or gas service plan types if they are reasonably assured of meeting the minimum required volumes of 340,000 m^3 for requesting large volume contracts. The regression model does not predict the 2011 Budget rate switching for a heterogeneous customer mix that has different individual usage pattern. Therefore, the impact of migration on the contract market in both the 2010 estimate and the 2011 budget are layered onto the regression model's average use forecast.

15. Changes in rate design that were accepted in the IR Settlement Agreement in EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, pages 33 and 34, have reduced the cost difference between general service and contract rate classes for contract customers. Specifically, these rate design changes reflect the implementation of increasing monthly customer charges for Rate 1 and Rate 6 on a revenue neutral basis. Consequently, Rate 100 customers may benefit by migrating to Rate 6. These changes helped to increase the rate switching trend experienced during years 2006 to 2009.

16. Figures 3 to 5 on the next several pages show the contract market unlocks between 2006 and 2009. They 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

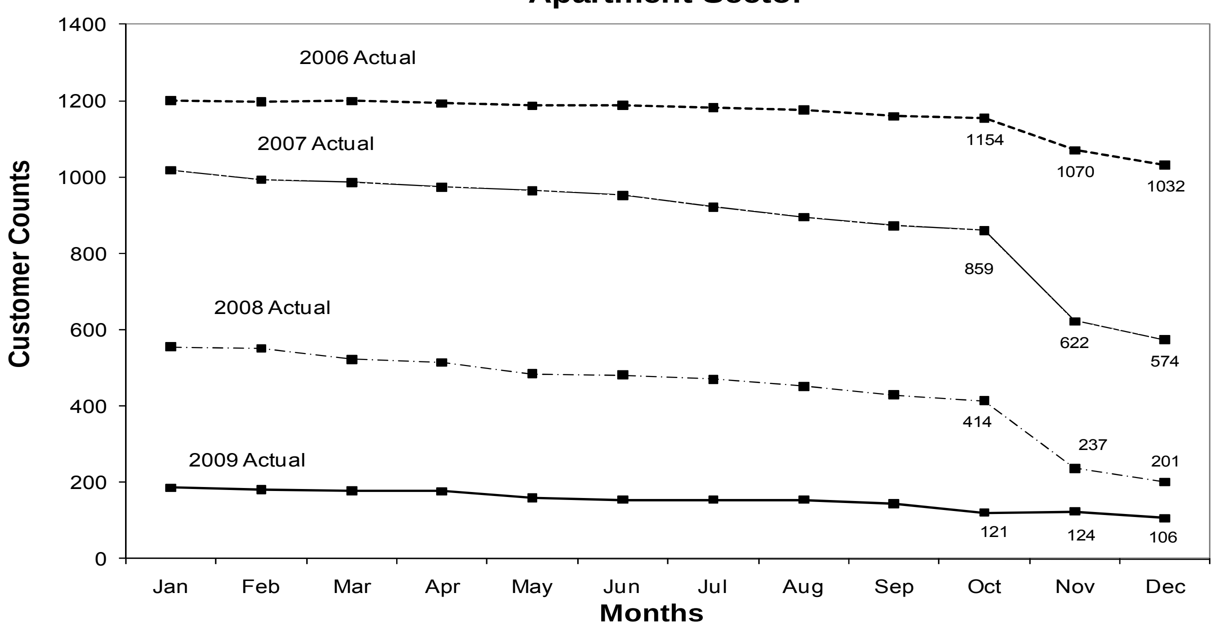


Figure 4: Contract Market Unlock Customers
Commercial Sector

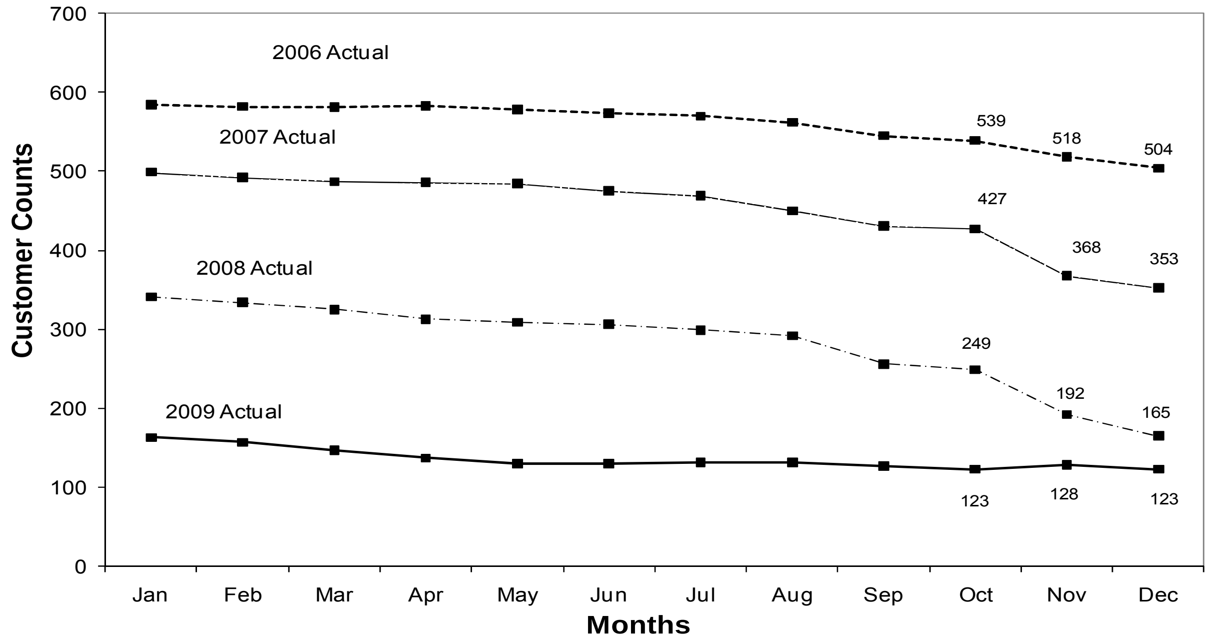
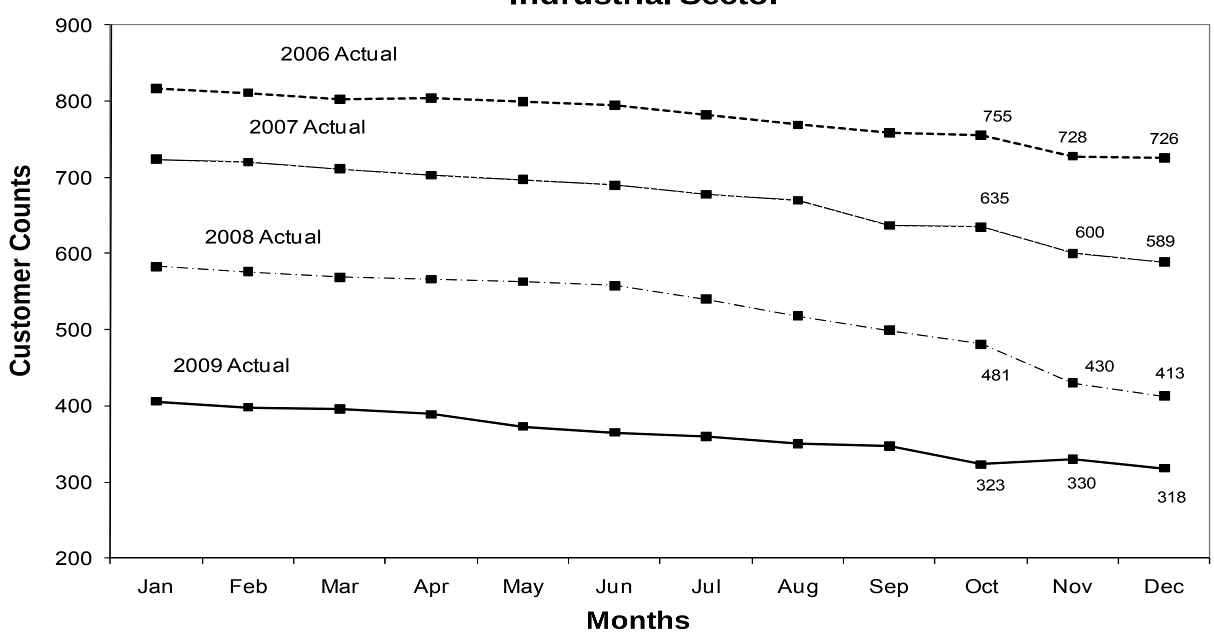


Figure 5: Contract Market Unlock Customers
Indrustrial Sector



Contract Market Volume Forecast Methodology

17. The volumes in the contract market are generated using the established and approved grass roots approach. Volumes are forecast on an individual customer basis by account executives in consultation with customers during the budget process. Specifically, the account executives review the contract attributes (e.g., rate and plan type) for each contract in order to ensure that the customer can meet the contracted rate class minimum volume and load factor requirements. Current economic and industry conditions and budgeted degree days, are factored into the budget determination. The 2010 Bridge Year estimate for contract market customers has also incorporated three months of 2010 actual information.

Contract Market Volumes: 2011 Budget

18. The 2011 Budget Contract Market volumes are 2,022.9 10^6m^3. Contract market volumes suffered a steep decline during the recent economic downturn, particularly in energy intensive manufacturing industries, such as pulp & paper, transportation equipment, primary metal, non-metallic mineral and chemical. After four consecutive declines in Ontario real manufacturing output as shown in Table 10 at Exhibit B, Tab 1, Schedule 7, page 21, most of the major economic indicators in Ontario have improved from lows during the decline. The economy is expected to gradually improve in 2011. However, with a strong Canadian dollar, rising transportation costs and global competition, the prospects for the contract market appear to be weak despite the improvement in the economy. Overall, the 2011 budget represents the forecast that integrates actual experience and the best available information at the time of the development of the budget.

Comparison of 2011 Budget and 2010 Estimate - Summary

19. The 2011 Budget volumes reflect the meter reading heating degree days forecast for the Central Region of 3,602, an increase of 56 degree days compared to the 2010 Board Approved level of 3,546. Meter reading heating degree days are determined by amalgamating Gas Supply heating degree days with the billing schedules. Evidence related to the forecast of Gas Supply heating degree days is presented at Exhibit B, Tab 1, Schedule 6.

20. The 2011 Budget volumes of 11 306.3 10^6m^3 are forecast to be 154.7 10^6m^3 or 1.4% above the 2010 Bridge Year Estimate of 11 151.6 10^6m^3. This increase is primarily attributable to the higher degree day forecast and other factors discussed below. On a weather-normalized basis, the 2011 Budget volumes are forecast to be 54.6 10^6m^3 or 0.5% above the 2010 Bridge Year Estimate. The increase on a normalized basis is made up of an increase in general service volumes of 98.3 10^6m^3, partially offset by a decrease in the contract market of 43.7 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 1 to 6.

21. The increase in the general service volumes of 98.3 10^6m^3 on a weather-normalized basis is primarily due to customer growth of 89.5 10^6m^3 and rate switching from a contract rate to general service (or transfer gains) of 28.0 10^6m^3. The customer growth mitigates the lower average use per customer of 18.7 10^6m^3. Lower average use results from the 2011 Demand Side Management ("DSM") plan, conservation initiatives originated by customers themselves or promoted by government programs, and improved building envelopes.

22. Table 3 on the next page 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 59.3 10^6m^3 is a result of customer growth, partially offset by the ongoing average use decline as shown in Figure 1.

Table 3

Factors Influencing the Changes in Residential Gas Consumption

Between 2011 Test Year Budget and 2010 Bridge Year Estimate (10^6m^3)

Factors	**Total Volume (10^6m^3)**	
Customer Growth	75.1	
DSM Initiatives	(12.7)	
New Homes - historical trend (a)	(10.2)	
Gas Prices	3.5	
Other Conservation (b)	0.0	*
Gas Appliances (c)	3.6	
Total	59.3	

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

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

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

* Less than 50,000 m^3

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

increase in Rate 6 volumes of 39.7 10^6m^3 is primarily due to rate switching from contract rate to a general service rate class of 28.0 10^6m^3 and customer growth of 14.4 10^6m^3.

Table 4

Factors Influencing the Changes in Rate 6 Gas Consumption

Between 2011 Test Year Budget and 2010 Bridge Year Estimate (10^6m^3)

Factors	Apartment (10^6m^3)	Commercial (10^6m^3)	Industrial (10^6m^3)	Total Volume (10^6m^3)
Customer Growth	1.1	13.3	0.0	14.4
DSM Initiatives	(11.6)	(11.6)	(2.9)	(26.1)
Economics, Gas Appliances (a)	12.7	9.7	14.3	36.7
Rate Switching - change in rate design (b)	13.0	6.0	9.0	28.0
Other Conservation (c)	(7.3)	0.1	(11.3)	(18.5)
Gas Prices	4.9	0.0	0.3	5.2
Total	12.8	17.5	9.4	39.7

(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 rate 6 average use, such as transfer gains/losses impact on average uses, vacancy rate, etc

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

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

24. The 2011 large volume budget is expected to be 43.7 10^6m^3 lower than the 2010 Estimate on a weather-normalized basis. The underage is mainly caused by customer migration from contract market to general service (or transfer losses) of 28.0 10^6m^3 along with a change in usage. After removing the unfavourable rate switching volumetric impact, the 2011 contract market volume budget is expected to be 15.7 10^6m^3 lower than the 2010 Estimate on a weather normalized basis. The variance is primarily due to a decrease in wholesale market customers (Rate 200), and partially offset by adding two new customers. Table 5 on the following page, illustrates major variance drivers contributing to the reduction in contract market volumes between 2011 Budget and 2010 Estimate. Table 6 and Table 7 on pages 16 to 17, present the 2011 Budget volume resulting from new and lost customers. Table 8 on page 18, illustrates migration to Rate 6 by trade group.

Table 5 - Comparison of Contract Market Volumes
2011 Budget and 2010 Bridge Year Estimate
(10^6m^3)

	Col. 1	Col. 2	Col. 3
	2011 Budget	2010 Bridge Year Estimate	2011 Budget Over (Under) 2010 Estimate
			(1-2)
Contract Market Total Gas Sales and Transportation Volumes	2,022.9	2,061.7	(38.8)
Major Variance Factors:			
Weather Normalization, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 4, Col. 4, Item No. 4			4.9
New Customers - Table 9			6.6
Lost customers - Table 8			(1.5)
Transfer losses - migration of customers from contract rates to general service rate 6			(28.0)
Wholesale customer - price impact, switching use from gas to oil			(12.7)
Impact of economy on Construction Industries customers			(5.1)
Impact of economy on Non-Metallic Mineral Products customers			(3.0)
Others change in usage (e.g. change in production process, etc.)			(0.1)
Total Major Variance Factors:			**(38.8)**

Table 6 - New Customers
Between 2011 Test Year Budget and 2010 Bridge Year Estimate

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	1	Electronics/High Tech	1.1
	1	Food, Beverage, Drug & Tobacco	5.5
Grand Total	**2**		**6.6**

Table 7 - Lost Customers
Between 2011 Test Year Budget and 2010 Bridge Year Estimate

1. Industrial Plants Relocation to Area Outside the Franchise

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(2)	Chemical and Chemical Products	(0.1)
	(1)	Primary Metal & Machinery	(0.1)
	(1)	Pulp & Paper	(0.1)
Total	(4)		(0.3)

2. Industrial Plant Closure

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(1)	Primary Metal & Machinery	(0.4)
	(1)	Pulp & Paper	(0.8)
Total	(2)		(1.2)
Grand Total	**(6)**		**(1.5)**

Table 8 - Customer Migration from Contract Rate to Rate 6
Between 2011 Budget and 2010 Bridge Year Estimate

1. Customers that migrating to Rate 6 in 2010

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(26)	Apartment	(11.0)
	(2)	Chemical and Chemical Products	(0.2)
	(2)	Education Services	(1.5)
	(1)	Food, Beverage, Drug & Tobacco	(0.5)
	(1)	Hotels	(0.2)
	(1)	Other Utility Industries (Cogen)	(2.1)
	(2)	Primary Metal & Machinery	(0.6)
	(2)	Pulp & Paper	(0.3)
	(3)	Rubber Products	(1.5)
	(2)	Textile Products	(0.3)
	(2)	Transportation Equipment	(1.4)
	(1)	Wholesale & Retail Trade	(0.2)
Total	(45)		(19.8)

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

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(5)	Apartment	(2.1)
	(1)	Business & Financial Service Industries	(0.5)
	(2)	Chemical and Chemical Products	(1.2)
	(1)	Other Utility Industries (Cogen)	(1.5)
	(1)	Primary Metal & Machinery	(0.9)
	(1)	Wood & Furniture Industries	(2.0)
Total	(11)		(8.2)
Grand Total	**(56)**		**(28.0)**

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

Comparison of 2010 Estimate and 2010 Board Approved

25. The Estimate volume of 11 151.6 10^6m^3 is forecast to be 59.5 10^6m^3 or 0.5% above the 2010 Board Approved Budget of 11 092.1 10^6m^3. The increase on a normalized basis is made up of increases in general service volumes of 6.4 10^6m^3 and in the contract market of 53.1 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 8 to 10.

26. The increase in the general service volumes of 6.4 10^6m^3 is primarily due to net rate switching gains from contract rate class to a general service rate class (or transfer gains) of 51.6 10^6m^3 mainly due to migration, and customer growth of 7.4 10^6m^3. It is partially offset by customer losses of 32.9 10^6m^3 and lower general service average use 19.7 10^6m^3. Customer losses are primarily driven by plant closures or relocations of Rate 6 large volume customers of 32.6 10^6m^3 and the losses of NGV stations of 0.3 10^6m^3, which were impacted by poor economic conditions in 2009. Lower general service average use is comprised of lower residential average use of 6.0 10^6m^3 and lower Rate 6 average use 13.6 10^6m^3, mainly due to the Company's DSM initiatives and other conservation initiatives originated by customers themselves or promoted by the government.

27. The increase in the large volume of 53.1 10^6m^3 is primarily due to improvement in market conditions during 2010. Table 9 on the next page, shows major variance drivers contributing to these variances by trade group. The increase is partially offset by customer migration to general service of 51.6 $10^6m^3$and ongoing contract market customer losses relating to either plant closures or consolidation (i.e., relocation outside the franchise area) of 14.4 10^6m^3 as shown on Table 10 on page 21. Tables 11 and 12 on pages 22 to 23, present rate switching between contract market and general service.

Table 9 - Comparison of Contract Market Volumes
2010 Bridge Year Estimate and 2010 Board Approved Budget
($10^6 m^3$)

	Col. 1	Col. 2	Col. 3
	2010 Bridge Year Estimate	2010 Budget	2010 Estimate Over (Under) 2010 Budget
			(1-2)
Contract Market Total Gas Sales and Transportation Volumes	2,061.7	2,008.6	53.1
Major Variance Factors:			
Weather Normalization, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 4, Col. 4, Item No. 4			0.0
Lost customers - Table 15			(14.4)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			25.3
Transfer losses - migration of customers from contract rates to general service rate 6			(76.9)
Wholesale customer - improve of economy			12.1
Improvement of economy and lower gas prices than oil - Refined Petroleum Industry			33.3
Improvement of economy and price spread between Hydro and Gas - Distributed Energy customers			23.5
Return to normal load due to past service interruption			18.6
Improvement of economy - Non-Metallic Mineral Products Industry			14.2
Improvement of economy - Transportation Equipment Industry			13.9
Improvement of economy - Chemical and Chemical Products Industry			10.9
Impact of economy on one landfill gas customer			(5.9)
Others change in usage (e.g. change in production process, etc.)			(1.5)
Total Major Variance Factors:			**53.1**

Table 10 - Lost Customers
Between 2010 Bridge Year Estimate and 2010 Board Approved Budget

1. Industrial Plants Relocation to Area Outside the Franchise

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(2)	Chemical and Chemical Products	(1.7)
	(1)	Non-Metallic Mineral Products	(1.3)
	(1)	Primary Metal & Machinery	(4.0)
	(1)	Pulp & Paper	(0.6)
Total	(5)		(7.6)

2. Industrial Plant Closure

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(1)	Chemical and Chemical Products	(2.6)
	(2)	Primary Metal & Machinery	(1.7)
	(2)	Pulp & Paper	(2.5)
Total	(5)		(6.8)
Grand Total	**(10)**		**(14.4)**

Table 11 - Customer Migration from Contract Rate to Rate 6
Between 2010 Bridge Year Estimate and 2010 Board Approved Budget

1. Customers that already migrated to Rate 6 in 2010

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(2)	Apartment	(0.9)
	(7)	Asphalt	(7.1)
	(3)	Chemical and Chemical Products	(6.0)
	(1)	Education Services	(0.8)
	(3)	Food, Beverage, Drug & Tobacco	(6.2)
	(1)	Government Services	(31.9)
	(2)	Greenhouses/Agriculture	(1.1)
	(1)	Hotels	(0.3)
	(1)	Non-Metallic Mineral Products	(0.9)
	(5)	Primary Metal & Machinery	(3.1)
	(4)	Pulp & Paper	(5.2)
	(2)	Textile Products	(1.9)
	(6)	Transportation Equipment	(11.2)
Total	(38)		(76.6)

2. Customers that will be migrated to Rate 6 in Fall 2010

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(1)	Primary Metal & Machinery	(0.3)
Total	(1)		(0.3)
Grand Total	**(39)**		**(76.9)**

*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.

Table 12 - Customer Migration from Rate 6 to Contract Rate
Between 2010 Bridge Year Estimate and 2010 Board Approved Budget

1. Customers that migrate to Rate 6 in 2010

	Number of Customers*	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	27	Apartment	11.3
	1	Education Services	0.8
	1	Other Utility Industries (Cogen)	2.0
	3	Rubber Products	1.5
	1	Textile Products	0.0
	2	Transportation Equipment	1.4
	1	Wholesale & Retail Trade	0.2
Total	36		17.2

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

	Number of Customers*	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	5	Apartment	2.1
	1	Business & Financial Service Industries	0.5
	1	Wood & Furniture Industries	2.0
Total	7		4.6

3. Customers stayed at contract due to improved market conditions

	Number of Customers*	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
	2	Apartment	1.1
	1	Electronics/High Tech	0.6
	1	Primary Metal & Machinery	1.8
Total	4		3.5
Grand Total	**47**		**25.3**

*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.

Comparison of 2010 Estimate and 2009 Actual

28. The Estimate volumes of 11 151.6 10^6m^3 are forecast to be 183.2 10^6m^3 or 1.6% below the 2009 Actual of 11 334.8 10^6m^3. The unfavourable variance is primarily due to warmer weather forecast in 2010 than in 2009 Actual. On a weather-normalized basis the 2010 Bridge Year Estimate volumes are 77.8 10^6m^3 or 0.7% above the 2009 Actual. The increase on a normalized basis is made up of an increase in general service volumes of 203.0 10^6m^3 and a decrease in the contract market of 125.2 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 11 to 14.

29. The increase in the general service volumes of 203.0 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 126.7 10^6m^3 and customer growth of 131.2 10^6m^3. It is partially offset by decreases in general service average use of 23.8 10^6m^3 along with customer loss in load of 31.1 10^6m^3. The reduction in general service average use is comprised of lower residential average use of 1.0 10^6m^3 and lower Rate 6 average use of 23.1 10^6m^3, partially offset by a slight increase in usage in Rate 9 of 0.3 10^6m^3. Reduction in general service average uses are mainly due to the Company's DSM initiatives and other conservation initiatives originated by customers themselves or promoted by the government. Customer losses are primarily driven by plant closures or relocations for Rate 6 large volume customers and the loss of NGV stations, which are impacted by poor market conditions.

30. The decrease in the contract market volumes of 125.2 10^6m^3 on a weather-normalized basis is primarily due to rate switching from contract rates to a general service rate class (or transfer losses) of 126.7 10^6m^3 as mentioned above. Absent

rate switching, the 2010 contract market volumes are 1.5 10^6m^3 above the 2009 actual. The variance is primarily due to production increases by customers as a result of improved market conditions, in particular in the Pulp and Paper industries and Non-Metallic Minerals Products industries. This is partially offset by the impact on distributed energy customers of a larger price spread between natural gas and electricity and the loss of industrial customers due to plant closures and relocations outside the franchise area. Table 13 below, illustrates major drivers contributing to these variances by trade group. Tables 14 and 15 on pages 28 and 29, present lost customers and customer migration to Rate 6 by trade group, respectively.

Table 13 - Comparison of Contract Market Volumes
2010 Bridge Year Estimate and 2009 Actual
(10^6m^3)

	Col. 1	Col. 2	Col. 3
	2010 Bridge Year Estimate	2009 Actual	2010 Estimate Over (Under) 2009 Actual
			(1-2)
Contract Market Total Gas Sales and Transportation Volumes	2,061.7	2,205.6	(143.9)
Major Variance Factors:			
Weather Normalization, Exhibit B, Tab 1, Schedule 5, Appendix A, Page 4, Col. 4, Item No. 4			(18.7)
Lost customers - Table 12			(15.0)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			15.8
Transfer losses - migration of customers from contract rates to general service rate 6			(142.5)
Wholesale customer - anticipation of increase in gas prices by pulp and paper customers			(3.9)
Return to normal load due to past service interruption			30.2
Impact of economy and price spread between hydro and gas on Distributed Energy customers			(28.1)
Improvement of economy - Pulp & Paper Industry			11.6
Improvement of economy - Non-Metallic Mineral Products Industry			7.2
Impact of economy on Food, Beverage, Drug & Tobacco Industry			(1.5)
Others change in usage (e.g. change in production process, etc.)			1.0
Total Major Variance Factors:			**(143.9)**

Table 14 - Lost Customers
Between 2010 Bridge Year Estimate and 2009 Actual

1. Industrial Plants Relocation to Area Outside the Franchise

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(2)	Chemical and Chemical Products	(1.2)
	(1)	Food, Beverage, Drug & Tobacco	(0.2)
	(1)	Non-Metallic Mineral Products	(0.6)
	(1)	Primary Metal & Machinery	(3.7)
	(1)	Pulp & Paper	(0.2)
Total	(6)		(5.9)

2. Industrial Plant Closure

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(1)	Chemical and Chemical Products	(0.5)
	(5)	Primary Metal & Machinery	(5.8)
	(2)	Pulp & Paper	(0.5)
	(1)	Transportation Equipment	(2.3)
Total	(9)		(9.1)
Grand Total	**(15)**		**(15.0)**

Table 15 - Customer Migration from Contract Rate to Rate 6
Between 2010 Bridge Year Estimate and 2009 Actual

	Number of Customers*	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(120)	Apartment	(34.9)
	(8)	Asphalt	(2.3)
	(7)	Business & Financial Service Industries	(4.3)
	(6)	Chemical and Chemical Products	(7.9)
	(1)	Construction Industries	(0.0)
	(4)	Education Services	(2.4)
	(16)	Food, Beverage, Drug & Tobacco	(11.1)
	(10)	Government Services	(31.6)
	(3)	Greenhouses/Agriculture	(1.4)
	(1)	Health, Social & Other Services	(0.5)
	(9)	Hotels	(3.3)
	(1)	Non-Metallic Mineral Products	(0.3)
	(1)	Plastic Products	(0.4)
	(22)	Primary Metal & Machinery	(8.4)
	(11)	Pulp & Paper	(5.0)
	(2)	Recreational & Household Industries	(0.3)
	(4)	Rubber Products	(1.6)
	(3)	Textile Products	(1.8)
	(2)	Transportation and Storage and Utilities	(0.6)
	(18)	Transportation Equipment	(21.4)
	(6)	Wholesale & Retail Trade	(2.6)
	(1)	Wood & Furniture Industries	(0.7)
Total	(256)		(142.5)

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

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

31. 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 2006 and subsequent years are presented on a calendar-year basis.

32. Appendix A, on page 23 illustrates 15 Years of Normalized Actual vs. Board Approved volumes Other than the unexpected, first time historic high natural gas prices in 2001 (Figure 1 on page 4) 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 the recession in 2009, average normalized percentage error variances between 2002 and 2004 as well as 2007 were merely 0.2% or 6 m^3 for Rate 1 average use per customer.

33. Unexpected increases in gas prices in 2001, 2005 and 2006 as previously mentioned in the EB-2006-0034 proceeding explained variances to Board Approved Budget numbers. This also accounts for the Board Approved Budget for 2007 that was lower than the Actual when gas prices were lower than forecast. As noted in EB-2009-0172, Exhibit B, Tab 1, Schedule 5, the unexpected major financial downturn contributed significantly to the shortfall in 2009 average uses.

34. As discussed previously, migration has had a significant impact since 2006. Appendix A, page 25 illustrates 9 Years of Normalized Actual vs. Board Approved volumes for contract market customers to evaluate the accuracy of forecast volumes.

Weather Normalization Methodology

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

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

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

adjusted to reflect normal weather by multiplying the Budget Heating Degree Days. Consequently, total normalized average use per customer is defined as an aggregate sum of baseload use per customer and normalized heatload per customer.

38. In the EBRO 465 Decision with Reasons, paragraph 3.1.16, 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 was proposed in EBRO 473 and the Board accepted this change in methodology.

39. In EBRO 487, approval was granted for a change from the traditional $18^{O}C$ balance point temperature assumption to a new temperature for purposes of normalizing average general service customer uses. This new normalizing technique has been 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.

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

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
2011 BUDGET

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)
General Service			
1.1.1	Rate 1 - Sales	1 269 606	3 356.3
1.1.2	Rate 1 - T-Service	534 583	1 408.1
1.1	Total Rate 1	1 804 189	4 764.4
1.2.1	Rate 6 - Sales	117 393	2 235.7
1.2.2	Rate 6 - T-Service	43 434	2 282.7
1.2	Total Rate 6	160 827	4 518.4
1.3.1	Rate 9 - Sales	10	0.4
1.3.2	Rate 9 - T-Service	1	0.2
1.3	Total Rate 9	11	0.6
1.	Total General Service Sales & T-Service	1 965 027	9 283.4
Contract Sales			
2.1	Rate 100	0	0.0
2.2	Rate 110	34	64.5
2.3	Rate 115	1	0.4
2.4	Rate 135	1	0.6
2.5	Rate 145	12	22.3
2.6	Rate 170	5	49.9
2.7	Rate 200	1	157.4
2.	Total Contract Sales	54	295.1
Contract T-Service			
3.1	Rate 100	0	0.0
3.2	Rate 110	170	407.4
3.3	Rate 115	33	512.7
3.4	Rate 125	4	0.0 *
3.5	Rate 135	32	49.4
3.6	Rate 145	175	215.0
3.7	Rate 170	34	513.3
3.8	Rate 300	9	30.0
3.9	Rate 315	0	0.0
3.	Total Contract T-Service	457	1 727.8
4.	Total Contract Sales & T-Service	511	2 022.9
5.	Total	1 965 538	11 306.3

* There is no distribution volume for Rate 125 customers.

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

		Col. 1	Col. 2	Col. 3
Item No.		2011 Budget	2010 Bridge Year Estimate	2011 Budget Over (Under) 2010 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 269 606	1 249 516	20 090
1.1.2	Rate 1 - T-Service	534 583	526 373	8 210
1.1	Total Rate 1	1 804 189	1 775 889	28 300
1.2.1	Rate 6 - Sales	117 393	116 646	747
1.2.2	Rate 6 - T-Service	43 434	42 638	796
1.2	Total Rate 6	160 827	159 284	1 543
1.3.1	Rate 9 - Sales	10	21	(11)
1.3.2	Rate 9 - T-Service	1	1	0
1.3	Total Rate 9	11	22	(11)
1.	Total General Service Sales & T-Service	1 965 027	1 935 195	29 832
Contract Sales				
2.1	Rate 100	0	6	(6)
2.2	Rate 110	34	36	(2)
2.3	Rate 115	1	0	1
2.4	Rate 135	1	1	0
2.5	Rate 145	12	11	1
2.6	Rate 170	5	5	0
2.7	Rate 200	1	1	0
2.	Total Contract Sales	54	60	(6)
Contract T-Service				
3.1	Rate 100	0	20	(20)
3.2	Rate 110	170	175	(5)
3.3	Rate 115	33	31	2
3.4	Rate 125	4	4	0
3.5	Rate 135	32	32	0
3.6	Rate 145	175	176	(1)
3.7	Rate 170	34	34	0
3.8	Rate 300	9	9	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	457	481	(24)
4.	Total Contract Sales & T-Service	511	541	(30)
5.	Total	1 965 538	1 935 736	29 802

COMPARISON OF GAS SALES AND TRANSPORTATION VOLUME BY RATE CLASS 2011 BUDGET AND 2010 BRIDGE YEAR ESTIMATE

(10^6m^3)

Item No.		Col. 1 2011 Budget	Col. 2 2010 Bridge Year Estimate	Col. 3 2011 Budget Over (Under) 2010 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 356.3	3 274.3	82.0
1.1.2	Rate 1 - T-Service	1 408.1	1 373.2	34.9
1.1	Total Rate 1	4 764.4	4 647.5	116.9
1.2.1	Rate 6 - Sales	2 235.7	2 220.5	15.2
1.2.2	Rate 6 - T-Service	2 282.7	2 220.6	62.1
1.2	Total Rate 6	4 518.4	4 441.1	77.3
1.3.1	Rate 9 - Sales	0.4	1.1	(0.7)
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0
1.3	Total Rate 9	0.6	1.3	(0.7)
1.	Total General Service Sales & T-Service	9 283.4	9 089.9	193.5
Contract Sales				
2.1	Rate 100	0.0	4.3	(4.3)
2.2	Rate 110	64.5	67.9	(3.4)
2.3	Rate 115	0.4	0.2	0.2
2.4	Rate 135	0.6	0.6	0.0
2.5	Rate 145	22.3	22.2	0.1
2.6	Rate 170	49.9	51.3	(1.4)
2.7	Rate 200	157.4	168.2	(10.8)
2.	Total Contract Sales	295.1	314.7	(19.6)
Contract T-Service				
3.1	Rate 100	0.0	16.5	(16.5)
3.2	Rate 110	407.4	500.6	(93.2)
3.3	Rate 115	512.7	407.8	104.9
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	49.4	49.6	(0.2)
3.6	Rate 145	215.0	217.1	(2.1)
3.7	Rate 170	513.3	520.3	(7.0)
3.8	Rate 300	30.0	35.1	(5.1)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 727.8	1 747.0	(19.2)
4.	Total Contract Sales & T-Service	2 022.9	2 061.7	(38.8)
5.	Total	11 306.3	11 151.6	154.7

* There is no distribution volume for Rate 125 customers.

Witness: R. Lei

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

Item No.		Col. 1 2011 Budget	Col. 2 2010 Bridge Year Estimate	Col. 3 2011 Budget Over (Under) 2010 Estimate (1-2)	Col. 4 2010* Adjustments		Col. 5 2011 Budget Over (Under) 2010 Estimate with Adjustments (3-4)
General Service							
1.1.1	Rate 1 - Sales	3 356.3	3 274.3	82.0	40.8		41.2
1.1.2	Rate 1 - T-Service	1 408.1	1 373.2	34.9	16.8		18.1
1.1	Total Rate 1	4 764.4	4 647.5	116.9	57.6		59.3
1.2.1	Rate 6 - Sales	2 235.7	2 220.5	15.2	17.5		(2.3)
1.2.2	Rate 6 - T-Service	2 282.7	2 220.6	62.1	20.1		42.0
1.2	Total Rate 6	4 518.4	4 441.1	77.3	37.6		39.7
1.3.1	Rate 9 - Sales	0.4	1.1	(0.7)	0.0		(0.7)
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0	0.0		0.0
1.3	Total Rate 9	0.6	1.3	(0.7)	0.0		(0.7)
1.	Total General Service Sales & T-Service	9 283.4	9 089.9	193.5	95.2		98.3
Contract Sales							
2.1	Rate 100	0.0	4.3	(4.3)	0.0	**	(4.3)
2.2	Rate 110	64.5	67.9	(3.4)	0.0	**	(3.4)
2.3	Rate 115	0.4	0.2	0.2	0.0		0.2
2.4	Rate 135	0.6	0.6	0.0	0.0		0.0
2.5	Rate 145	22.3	22.2	0.1	0.1		0.0
2.6	Rate 170	49.9	51.3	(1.4)	0.1		(1.5)
2.7	Rate 200	157.4	168.2	(10.8)	1.9		(12.7)
2.	Total Contract Sales	295.1	314.7	(19.6)	2.1		(21.7)
Contract T-Service							
3.1	Rate 100	0.0	16.5	(16.5)	0.1		(16.6)
3.2	Rate 110	407.4	500.6	(93.2)	0.3		(93.5)
3.3	Rate 115	512.7	407.8	104.9	0.0	**	104.9
3.4	Rate 125	0.0	0.0	0.0	0.0		0.0
3.5	Rate 135	49.4	49.6	(0.2)	0.0		(0.2)
3.6	Rate 145	215.0	217.1	(2.1)	0.9		(3.0)
3.7	Rate 170	513.3	520.3	(7.0)	1.5		(8.5)
3.8	Rate 300	30.0	35.1	(5.1)	0.0		(5.1)
3.9	Rate 315	0.0	0.0	0.0	0.0		0.0
3.	Total Contract T-Service	1 727.8	1 747.0	(19.2)	2.8		(22.0)
4.	Total Contract Sales & T-Service	2 022.9	2 061.7	(38.8)	4.9		(43.7)
5.	Total	11 306.3	11 151.6	154.7	100.1		54.6

* Note: Weather normalization adjustments have been made to the 2010 Bridge Year Estimate utilizing the 2011 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 2011 BUDGET AND 2010 BRIDGE YEAR ESTIMATE

(10^6m^3)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
Item No.		2011 Budget	2010 Bridge Year Estimate	2011 Budget Over (Under) 2010 Estimate (1-2)	Change in Use	Weather	New Customers	Transfer Gains	Transfer Losses	Lost Customers	Added Load
General Service											
1.1.1	Rate 1 - Sales	3 356.3	3 274.3	82.0	(12.2)	40.8	53.4	0.0	0.0	0.0	0.0
1.1.2	Rate 1 - T-Service	1 408.1	1 373.2	34.9	(3.6)	16.8	21.7	0.0	0.0	0.0	0.0
1.1	Total Rate 1	4 764.4	4 647.5	116.9	(15.8)	57.6	75.1	0.0	0.0	0.0	0.0
1.2.1	Rate 6 - Sales	2 235.7	2 220.5	15.2	(22.7)	17.5	14.4	6.0	0.0	0.0	0.0
1.2.2	Rate 6 - T-Service	2 282.7	2 220.6	62.1	20.0	20.1	0.0	22.0	0.0	0.0	0.0
1.2	Total Rate 6	4 518.4	4 441.1	77.3	(2.7)	37.6	14.4	28.0	0.0	0.0	0.0
1.3.1	Rate 9 - Sales	0.4	1.1	(0.7)	(0.2)	0.0	0.0	0.0	0.0	(0.5)	0.0
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.3	Total Rate 9	0.6	1.3	(0.7)	(0.2)	0.0	0.0	0.0	0.0	(0.5)	0.0
1.	Total General Service	9 283.4	9 089.9	193.5	(18.7)	95.2	89.5	28.0	0.0	(0.5)	0.0
Contract Sales											
2.1	Rate 100	0.0	4.3	(4.3)	0.0	0.0 *	0.0	0.0	(4.3)	0.0	0.0
2.2	Rate 110	64.5	67.9	(3.4)	(2.8)	0.0 *	1.1	0.0	(1.7)	0.0	0.0
2.3	Rate 115	0.4	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
2.4	Rate 135	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.5	Rate 145	22.3	22.2	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0
2.6	Rate 170	49.9	51.3	(1.4)	(1.5)	0.1	0.0	0.0	0.0	0.0	0.0
2.7	Rate 200	157.4	168.2	(10.8)	(12.7)	1.9	0.0	0.0	0.0	0.0	0.0
2.	Total Contract Sales	295.1	314.7	(19.6)	(16.8)	2.1	1.1	0.0	(6.0)	0.0	0.0
Contract T-Service											
3.1	Rate 100	0.0	16.5	(16.5)	0.0	0.1	0.0	0.0	(16.5)	(0.2)	0.0
3.2	Rate 110	407.4	500.6	(93.2)	2.3	0.3	0.0	1.3	(95.8)	(1.3)	0.0
3.3	Rate 115	512.7	407.8	104.9	(5.6)	0.0 *	5.5	105.0	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	49.4	49.6	(0.2)	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0
3.6	Rate 145	215.0	217.1	(2.1)	(0.2)	0.9	0.0	0.0	(2.8)	0.0	0.0
3.7	Rate 170	513.3	520.3	(7.0)	(8.5)	1.5	0.0	0.0	0.0	0.0	0.0
3.8	Rate 300	30.0	35.1	(5.1)	(5.1)	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	1 727.8	1 747.0	(19.2)	(17.3)	2.8	5.5	106.3	(115.1)	(1.5)	0.0
4.	Total Contract Sales & T-Service	2 022.9	2 061.7	(38.8)	(34.1)	4.9	6.6	106.3	(121.1)	(1.5)	0.0
5.	Total	11 306.3	11 151.6	154.7	(52.7)	100.1	96.1	134.3	(121.1)	(2.0)	0.0

* Less than 50,000 m³.

Witness: R. Lei

The principal reasons for the variances contributing to the weather normalized decrease of 54.6 10^6m^3 in the 2011 Budget over the 2010 Bridge Year Estimate are as follows:

1. The volumetric increase of 59.3 10^6m^3 in Rate 1 is due to customer growth of 75.1 10^6m^3; partially offset by a lower average use per customer totalling 15.8 10^6m^3;

2. The volumetric increase of 39.7 10^6m^3 in Rate 6 is due to customer growth of 14.4 10^6m^3 and net customer migration from Contract Sales and T-Service of 28.0 10^6m^3; partially offset by a lower average use per customer totalling 2.7 10^6m^3;

3. The volumetric decrease of 0.7 10^6m^3 in Rate 9 is due to the loss of stations of 0.5 10^6m^3 and a lower average use per station of 0.2 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 43.7 10^6m^3 is due to decreases in the apartment sector of 13.2 10^6m^3, the commercial sector of 1.0 10^6m^3, the industrial sector of 16.8 10^6m^3 and Rate 200 of 12.7 10^6m^3. This decrease is primarily attributable to net customer migration to General Service of 28.0 10^6m^3 as stated above.

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2010 BRIDGE YEAR ESTIMATE

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)
	General Service		
1.1.1	Rate 1 - Sales	1 249 516	3 274.3
1.1.2	Rate 1 - T-Service	526 373	1 373.2
1.1	Total Rate 1	1 775 889	4 647.5
1.2.1	Rate 6 - Sales	116 646	2 220.5
1.2.2	Rate 6 - T-Service	42 638	2 220.6
1.2	Total Rate 6	159 284	4 441.1
1.3.1	Rate 9 - Sales	21	1.1
1.3.2	Rate 9 - T-Service	1	0.2
1.3	Total Rate 9	22	1.3
1.	Total General Service Sales & T-Service	1 935 195	9 089.9
	Contract Sales		
2.1	Rate 100	6	4.3
2.2	Rate 110	36	67.9
2.3	Rate 115	0	0.2
2.4	Rate 135	1	0.6
2.5	Rate 145	11	22.2
2.6	Rate 170	5	51.3
2.7	Rate 200	1	168.2
2.	Total Contract Sales	60	314.7
	Contract T-Service		
3.1	Rate 100	20	16.5
3.2	Rate 110	175	500.6
3.3	Rate 115	31	407.8
3.4	Rate 125	4	0.0 *
3.5	Rate 135	32	49.6
3.6	Rate 145	176	217.1
3.7	Rate 170	34	520.3
3.8	Rate 300	9	35.1
3.9	Rate 315	0	0.0
3.	Total Contract T-Service	481	1 747.0
4.	Total Contract Sales & T-Service	541	2 061.7
5.	Total	1 935 736	11 151.6

* There is no distribution volume for Rate 125 customers.

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

(10^6m^3)

Item No.		Col. 1 2010 Bridge Year Estimate	Col. 2 2010 Budget	Col. 3 2010 Estimate Over (Under) 2010 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 274.3	3 030.6	243.7
1.1.2	Rate 1 - T-Service	1 373.2	1 615.5	(242.3)
1.1	Total Rate 1	4 647.5	4 646.1	1.4
1.2.1	Rate 6 - Sales	2 220.5	1 990.4	230.1
1.2.2	Rate 6 - T-Service	2 220.6	2 445.3	(224.7)
1.2	Total Rate 6	4 441.1	4 435.7	5.4
1.3.1	Rate 9 - Sales	1.1	1.4	(0.3)
1.3.2	Rate 9 - T-Service	0.2	0.3	(0.1)
1.3	Total Rate 9	1.3	1.7	(0.4)
1.	Total General Service Sales & T-Service	9 089.9	9 083.5	6.4
Contract Sales				
2.1	Rate 100	4.3	0.0	4.3
2.2	Rate 110	67.9	43.9	24.0
2.3	Rate 115	0.2	4.4	(4.2)
2.4	Rate 135	0.6	5.9	(5.3)
2.5	Rate 145	22.2	25.2	(3.0)
2.6	Rate 170	51.3	79.7	(28.4)
2.7	Rate 200	168.2	156.1	12.1
2.	Total Contract Sales	314.7	315.2	(0.5)
Contract T-Service				
3.1	Rate 100	16.5	0.0	16.5
3.2	Rate 110	500.6	518.8	(18.2)
3.3	Rate 115	407.8	421.2	(13.4)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	49.6	52.2	(2.6)
3.6	Rate 145	217.1	196.8	20.3
3.7	Rate 170	520.3	463.4	56.9
3.8	Rate 300	35.1	41.0	(5.9)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 747.0	1 693.4	53.6
4.	Total Contract Sales & T-Service	2 061.7	2 008.6	53.1
5.	Total	11 151.6	11 092.1	59.5

* There is no distribution volume for Rate 125 customers.

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

Item No.		Col. 1 2010 Bridge Year Estimate	Col. 2 2010 Budget	Col. 3 2010 Estimate Over (Under) 2010 Budget (1-2)	Col. 4 2010* Adjustments	Col. 5 2010 Estimate Over (Under) 2010 Budget with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 274.3	3 030.6	243.7	0.0	243.7
1.1.2	Rate 1 - T-Service	1 373.2	1 615.5	(242.3)	0.0	(242.3)
1.1	Total Rate 1	4 647.5	4 646.1	1.4	0.0	1.4
1.2.1	Rate 6 - Sales	2 220.5	1 990.4	230.1	0.0	230.1
1.2.2	Rate 6 - T-Service	2 220.6	2 445.3	(224.7)	0.0	(224.7)
1.2	Total Rate 6	4 441.1	4 435.7	5.4	0.0	5.4
1.3.1	Rate 9 - Sales	1.1	1.4	(0.3)	0.0	(0.3)
1.3.2	Rate 9 - T-Service	0.2	0.3	(0.1)	0.0	(0.1)
1.3	Total Rate 9	1.3	1.7	(0.4)	0.0	(0.4)
1.	Total General Service Sales & T-Service	9 089.9	9 083.5	6.4	0.0	6.4
Contract Sales						
2.1	Rate 100	4.3	0.0	4.3	0.0	4.3
2.2	Rate 110	67.9	43.9	24.0	0.0	24.0
2.3	Rate 115	0.2	4.4	(4.2)	0.0	(4.2)
2.4	Rate 135	0.6	5.9	(5.3)	0.0	(5.3)
2.5	Rate 145	22.2	25.2	(3.0)	0.0	(3.0)
2.6	Rate 170	51.3	79.7	(28.4)	0.0	(28.4)
2.7	Rate 200	168.2	156.1	12.1	0.0	12.1
2.	Total Contract Sales	314.7	315.2	(0.5)	0.0	(0.5)
Contract T-Service						
3.1	Rate 100	16.5	0.0	16.5	0.0	16.5
3.2	Rate 110	500.6	518.8	(18.2)	0.0	(18.2)
3.3	Rate 115	407.8	421.2	(13.4)	0.0	(13.4)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	49.6	52.2	(2.6)	0.0	(2.6)
3.6	Rate 145	217.1	196.8	20.3	0.0	20.3
3.7	Rate 170	520.3	463.4	56.9	0.0	56.9
3.8	Rate 300	35.1	41.0	(5.9)	0.0	(5.9)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 747.0	1 693.4	53.6	0.0	53.6
4.	Total Contract Sales & T-Service	2 061.7	2 008.6	53.1	0.0	53.1
5.	Total	11 151.6	11 092.1	59.5	0.0	59.5

*Note: As 2010 Bridge Year Estimate degree days are same as 2010 Board Approved Budget Degree Days, normalization adjustment is not required in order to place the two years on a comparable basis.

The principal reasons for the variances contributing to the weather normalized increase of 59.5 10^6m^3 in the 2010 Bridge Year Estimate over the 2010 Board Approved Budget are as follows:

1. The volumetric increase of 1.4 10^6m^3 in Rate 1 is due to a favourable customer variance of 7.4 10^6m^3; partially offset by a lower average use per customer totalling 6.0 10^6m^3;

2. The volumetric increase of 5.4 10^6m^3 in Rate 6 is due to a net customer migration from Contract Sales and T-Service of 51.6 10^6m^3; partially offset by an unfavourable customer variance of 32.6 10^6m^3 and lower average use per customer totalling 13.6 10^6m^3;

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

4. The volumetric increase for Contract Sales and T-Service of 53.1 10^6m^3 is due to increases in the apartment sector of 15.7 10^6m^3, in the commercial sector of 1.8 10^6m^3, in the industrial sector of 23.5 10^6m^3 and Rate 200 of 12.1 10^6m^3.

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

		Col. 1	Col. 2	Col. 3
Item No.		2010 Bridge Year Estimate	2009 Actual	2010 Estimate Over (Under) 2009 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 249 516	1 140 498	109 018
1.1.2	Rate 1 - T-Service	526 373	591 689	(65 316)
1.1	Total Rate 1	1 775 889	1 732 187	43 702
1.2.1	Rate 6 - Sales	116 646	108 014	8 632
1.2.2	Rate 6 - T-Service	42 638	46 722	(4 084)
1.2	Total Rate 6	159 284	154 736	4 548
1.3.1	Rate 9 - Sales	21	24	(3)
1.3.2	Rate 9 - T-Service	1	2	(1)
1.3	Total Rate 9	22	26	(4)
1.	Total General Service Sales & T-Service	1 935 195	1 886 949	48 246
Contract Sales				
2.1	Rate 100	6	25	(19)
2.2	Rate 110	36	35	1
2.3	Rate 115	0	1	(1)
2.4	Rate 135	1	2	(1)
2.5	Rate 145	11	12	(1)
2.6	Rate 170	5	5	0
2.7	Rate 200	1	1	0
2.	Total Contract Sales	60	81	(21)
Contract T-Service				
3.1	Rate 100	20	88	(68)
3.2	Rate 110	175	205	(30)
3.3	Rate 115	31	37	(6)
3.4	Rate 125	4	3	1
3.5	Rate 135	32	31	1
3.6	Rate 145	176	173	3
3.7	Rate 170	34	28	6
3.8	Rate 300	9	10	(1)
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	481	575	(94)
4.	Total Contract Sales & T-Service	541	656	(115)
5.	Total	1 935 736	1 887 605	48 131

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

Item No.		Col. 1 2010 Bridge Year Estimate	Col. 2 2009 Actual	Col. 3 2010 Estimate Over (Under) 2009 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 274.3	3 119.7	154.6
1.1.2	Rate 1 - T-Service	1 373.2	1 625.8	(252.6)
1.1	Total Rate 1	4 647.5	4 745.5	(98.0)
1.2.1	Rate 6 - Sales	2 220.5	1 932.4	288.1
1.2.2	Rate 6 - T-Service	2 220.6	2 450.0	(229.4)
1.2	Total Rate 6	4 441.1	4 382.4	58.7
1.3.1	Rate 9 - Sales	1.1	1.1	0.0
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0
1.3	Total Rate 9	1.3	1.3	0.0
1.	Total General Service Sales & T-Service	9 089.9	9 129.2	(39.3)
Contract Sales				
2.1	Rate 100	4.3	17.4	(13.1)
2.2	Rate 110	67.9	59.8	8.1
2.3	Rate 115	0.2	4.4	(4.2)
2.4	Rate 135	0.6	0.6	0.0
2.5	Rate 145	22.2	25.7	(3.5)
2.6	Rate 170	51.3	77.0	(25.7)
2.7	Rate 200	168.2	179.3	(11.1)
2.	Total Contract Sales	314.7	364.2	(49.5)
Contract T-Service				
3.1	Rate 100	16.5	82.9	(66.4)
3.2	Rate 110	500.6	517.8	(17.2)
3.3	Rate 115	407.8	460.1	(52.3)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	49.6	51.3	(1.7)
3.6	Rate 145	217.1	222.6	(5.5)
3.7	Rate 170	520.3	467.4	52.9
3.8	Rate 300	35.1	39.3	(4.2)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 747.0	1 841.4	(94.4)
4.	Total Contract Sales & T-Service	2 061.7	2 205.6	(143.9)
5.	Total	11 151.6	11 334.8	(183.2)

* There is no distribution volume for Rate 125 customers.

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

(10^6m^3)

Item No.		Col. 1 2010 Bridge Year Estimate	Col. 2 2009 Actual	Col. 3 2010 Estimate Over (Under) 2009 Actual (1-2)	Col. 4 2009* Adjustments	Col. 5 2010 Estimate Over (Under) 2009 Actual with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 274.3	3 119.7	154.6	(122.4)	277.0
1.1.2	Rate 1 - T-Service	1 373.2	1 625.8	(252.6)	(61.0)	(191.6)
1.1	Total Rate 1	4 647.5	4 745.5	(98.0)	(183.4)	85.4
1.2.1	Rate 6 - Sales	2 220.5	1 932.4	288.1	(25.7)	313.8
1.2.2	Rate 6 - T-Service	2 220.6	2 450.0	(229.4)	(33.2)	(196.2)
1.2	Total Rate 6	4 441.1	4 382.4	58.7	(58.9)	117.6
1.3.1	Rate 9 - Sales	1.1	1.1	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0	0.0	0.0
1.3	Total Rate 9	1.3	1.3	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	9 089.9	9 129.2	(39.3)	(242.3)	203.0
Contract Sales						
2.1	Rate 100	4.3	17.4	(13.1)	(0.2)	(12.9)
2.2	Rate 110	67.9	59.8	8.1	(0.1)	8.2
2.3	Rate 115	0.2	4.4	(4.2)	0.0 **	(4.2)
2.4	Rate 135	0.6	0.6	0.0	0.0	0.0
2.5	Rate 145	22.2	25.7	(3.5)	(0.1)	(3.4)
2.6	Rate 170	51.3	77.0	(25.7)	0.0 **	(25.7)
2.7	Rate 200	168.2	179.3	(11.1)	(7.2)	(3.9)
2.	Total Contract Sales	314.7	364.2	(49.5)	(7.6)	(41.9)
Contract T-Service						
3.1	Rate 100	16.5	82.9	(66.4)	(1.0)	(65.4)
3.2	Rate 110	500.6	517.8	(17.2)	(1.3)	(15.9)
3.3	Rate 115	407.8	460.1	(52.3)	0.0 **	(52.3)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	49.6	51.3	(1.7)	0.0	(1.7)
3.6	Rate 145	217.1	222.6	(5.5)	(3.1)	(2.4)
3.7	Rate 170	520.3	467.4	52.9	(5.7)	58.6
3.8	Rate 300	35.1	39.3	(4.2)	0.0	(4.2)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 747.0	1 841.4	(94.4)	(11.1)	(83.3)
4.	Total Contract Sales & T-Service	2 061.7	2 205.6	(143.9)	(18.7)	(125.2)
5.	Total	11 151.6	11 334.8	(183.2)	(261.0)	77.8

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

** Less than 50,000 m³.

Witness: R. Lei

The principal reasons for the variances contributing to the weather normalized increase of 77.8 10^6m^3 in the 2010 Bridge Year Estimate over the 2009 Actual are as follows:

1. The volumetric increase of 85.4 10^6m^3 in Rate 1 is due to customer growth of 86.4 10^6m^3; partially offset by a lower average use per customer totalling 1.0 10^6m^3;

2. The volumetric increase of 117.6 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 126.7 10^6m^3 and net customer growth of 14.0 10^6m^3; partially offset by a lower average use per customer totalling 23.1 10^6m^3;

3. There was no volumetric change in Rate 9, in consequence of an increase in average use per station totalling 0.3 10^6m^3 that is completely offset by the loss of four stations of 0.3 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 125.2 10^6m^3 is due to decreases in the apartment sector of 42.1 10^6m^3, the industrial sector of 219.8 10^6m^3 and Rate 200 of 3.9 10^6m^3; partially offset by an increase in commercial sector of 140.6 10^6m^3. This decrease is primarily attributable to net customer migration to General Service of 126.7 10^6m^3 as stated above.

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2009 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	1 140 498	3 119.7	1 488.6
1.1.2	Rate 1 - T-Service	591 689	1 625.8	318.3
1.1	Total Rate 1	1 732 187	4 745.5	1 806.9
1.2.1	Rate 6 - Sales	108 014	1 932.4	766.4
1.2.2	Rate 6 - T-Service	46 722	2 450.0	245.7
1.2	Total Rate 6	154 736	4 382.4	1 012.1
1.3.1	Rate 9 - Sales	24	1.1	0.4
1.3.2	Rate 9 - T-Service	2	0.2	0.0 **
1.3	Total Rate 9	26	1.3	0.4
1.	Total General Service Sales & T-Service	1 886 949	9 129.2	2 819.4
Contract Sales				
2.1	Rate 100	25	17.4	7.6
2.2	Rate 110	35	59.8	15.9
2.3	Rate 115	1	4.4	1.2
2.4	Rate 135	2	0.6	0.1
2.5	Rate 145	12	25.7	8.1
2.6	Rate 170	5	77.0	19.4
2.7	Rate 200	1	179.3	44.1
2.	Total Contract Sales	81	364.2	96.4
Contract T-Service				
3.1	Rate 100	88	82.9	8.4
3.2	Rate 110	205	517.8	32.6
3.3	Rate 115	37	460.1	21.3
3.4	Rate 125	3	0.0 *	6.9
3.5	Rate 135	31	51.3	2.2
3.6	Rate 145	173	222.6	13.4
3.7	Rate 170	28	467.4	13.5
3.8	Rate 300	10	39.3	0.5
3.9	Rate 315	0	0.0	0.4
3.	Total Contract T-Service	575	1 841.4	99.2
4.	Total Contract Sales & T-Service	656	2 205.6	195.6
5.	Total	1 887 605	11 334.8	3 015.0

* There is no distribution volume for Rate 125 customers.

** Less than $50,000.

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

Item No.		Col. 1 2009 Actual	Col. 2 2008 Actual	Col. 3 2009 Actual Over (Under) 2008 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 140 498	1 078 118	62 380
1.1.2	Rate 1 - T-Service	591 689	630 402	(38 713)
1.1	Total Rate 1	1 732 187	1 708 520	23 667
1.2.1	Rate 6 - Sales	108 014	104 000	4 014
1.2.2	Rate 6 - T-Service	46 722	51 207	(4 485)
1.2	Total Rate 6	154 736	155 207	(471)
1.3.1	Rate 9 - Sales	24	26	(2)
1.3.2	Rate 9 - T-Service	2	3	(1)
1.3	Total Rate 9	26	29	(3)
1.	Total General Service Sales & T-Service	1 886 949	1 863 756	23 193
Contract Sales				
2.1	Rate 100	25	129	(104)
2.2	Rate 110	35	34	1
2.3	Rate 115	1	1	0
2.4	Rate 135	2	3	(1)
2.5	Rate 145	12	11	1
2.6	Rate 170	5	5	0
2.7	Rate 200	1	1	0
2.	Total Contract Sales	81	184	(103)
Contract T-Service				
3.1	Rate 100	88	580	(492)
3.2	Rate 110	205	209	(4)
3.3	Rate 115	37	48	(11)
3.4	Rate 125	3	3	0
3.5	Rate 135	31	37	(6)
3.6	Rate 145	173	164	9
3.7	Rate 170	28	29	(1)
3.8	Rate 300	10	10	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	575	1 080	(505)
4.	Total Contract Sales & T-Service	656	1 264	(608)
5.	Total	1 887 605	1 865 020	22 585

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

Item No.		Col. 1 2009 Actual	Col. 2 2008 Actual	Col. 3 2009 Actual Over (Under) 2008 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 119.7	2 985.6	134.1
1.1.2	Rate 1 - T-Service	1 625.8	1 738.7	(112.9)
1.1	Total Rate 1	4 745.5	4 724.3	21.2
1.2.1	Rate 6 - Sales	1 932.4	1 815.6	116.8
1.2.2	Rate 6 - T-Service	2 450.0	2 263.9	186.1
1.2	Total Rate 6	4 382.4	4 079.5	302.9
1.3.1	Rate 9 - Sales	1.1	1.8	(0.7)
1.3.2	Rate 9 - T-Service	0.2	0.4	(0.2)
1.3	Total Rate 9	1.3	2.2	(0.9)
1.	Total General Service Sales & T-Service	9 129.2	8 806.0	323.2
Contract Sales				
2.1	Rate 100	17.4	98.8	(81.4)
2.2	Rate 110	59.8	62.3	(2.5)
2.3	Rate 115	4.4	8.4	(4.0)
2.4	Rate 135	0.6	5.1	(4.5)
2.5	Rate 145	25.7	22.4	3.3
2.6	Rate 170	77.0	70.9	6.1
2.7	Rate 200	179.3	183.3	(4.0)
2.	Total Contract Sales	364.2	451.2	(87.0)
Contract T-Service				
3.1	Rate 100	82.9	494.0	(411.1)
3.2	Rate 110	517.8	602.2	(84.4)
3.3	Rate 115	460.1	627.4	(167.3)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	51.3	52.3	(1.0)
3.6	Rate 145	222.6	220.6	2.0
3.7	Rate 170	467.4	618.3	(150.9)
3.8	Rate 300	39.3	35.5	3.8
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 841.4	2 650.3	(808.9)
4.	Total Contract Sales & T-Service	2 205.6	3 101.5	(895.9)
5.	Total	11 334.8	11 907.5	(572.7)

* There is no distribution volume for Rate 125 customers.

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

Item No.		Col. 1 2009 Actual	Col. 2 2008 Actual	Col. 3 2009 Actual Over (Under) 2008 Actual (1-2)	Col. 4 2008* Adjustments	Col. 5 2009 Actual Over (Under) 2008 Actual with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 119.7	2 985.6	134.1	13.2	120.9
1.1.2	Rate 1 - T-Service	1 625.8	1 738.7	(112.9)	14.5	(127.4)
1.1	Total Rate 1	4 745.5	4 724.3	21.2	27.7	(6.5)
1.2.1	Rate 6 - Sales	1 932.4	1 815.6	116.8	2.9	113.9
1.2.2	Rate 6 - T-Service	2 450.0	2 263.9	186.1	(3.1)	189.2
1.2	Total Rate 6	4 382.4	4 079.5	302.9	(0.2)	303.1
1.3.1	Rate 9 - Sales	1.1	1.8	(0.7)	0.0	(0.7)
1.3.2	Rate 9 - T-Service	0.2	0.4	(0.2)	0.0	(0.2)
1.3	Total Rate 9	1.3	2.2	(0.9)	0.0	(0.9)
1.	Total General Service Sales & T-Service	9 129.2	8 806.0	323.2	27.5	295.7
Contract Sales						
2.1	Rate 100	17.4	98.8	(81.4)	0.0	(81.4)
2.2	Rate 110	59.8	62.3	(2.5)	0.0	(2.5)
2.3	Rate 115	4.4	8.4	(4.0)	0.0 **	(4.0)
2.4	Rate 135	0.6	5.1	(4.5)	0.0	(4.5)
2.5	Rate 145	25.7	22.4	3.3	0.0	3.3
2.6	Rate 170	77.0	70.9	6.1	(0.2)	6.3
2.7	Rate 200	179.3	183.3	(4.0)	(0.9)	(3.1)
2.	Total Contract Sales	364.2	451.2	(87.0)	(1.1)	(85.9)
Contract T-Service						
3.1	Rate 100	82.9	494.0	(411.1)	0.1	(411.2)
3.2	Rate 110	517.8	602.2	(84.4)	(0.1)	(84.3)
3.3	Rate 115	460.1	627.4	(167.3)	0.0 **	(167.3)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	51.3	52.3	(1.0)	0.0 **	(1.0)
3.6	Rate 145	222.6	220.6	2.0	2.3	(0.3)
3.7	Rate 170	467.4	618.3	(150.9)	13.9	(164.8)
3.8	Rate 300	39.3	35.5	3.8	0.0	3.8
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 841.4	2 650.3	(808.9)	16.2	(825.1)
4.	Total Contract Sales & T-Service	2 205.6	3 101.5	(895.9)	15.1	(911.0)
5.	Total	11 334.8	11 907.5	(572.7)	42.6	(615.3)

* Note: Weather normalization adjustments have been made to the 2008 Actuals utilizing the 2009 Exhibit B Tab 1 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 615.3 10^6m^3 in the 2009 Actual over the 2008 Actual are as follows:

1. The volumetric decrease of 6.5 10^6m^3 in Rate 1 is due to a lower average use per customer totalling 95.8 10^6m^3; partially offset by customer growth of 89.3 10^6m^3;

2. The volumetric increase of 303.1 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 392.4 10^6m^3 and net customer growth of 28.7 10^6m^3; partially offset by a lower average use per customer totalling 118.0 10^6m^3;

3. The volumetric decrease of 0.9 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 three stations of 0.2 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 911.0 10^6m^3 is due to decreases in the apartment sector of 165.7 10^6m^3, the commercial sector of 314.6 10^6m^3, the industrial sector of 427.6 10^6m^3 and Rate 200 of 3.1 10^6m^3. This decreases are primarily attributable to net customer migration to General Service of 392.4 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.

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
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010 Bridge Year Estimate	2011 Budget
Residential		3,047	2,923	2,912	2,899	2,844	2,776	2,736	2,733	2,685	2,667	2,651	2,643
	Change		(124)	(11)	(13)	(55)	(68)	(40)	(3)	(48)	(18)	(16)	(8)
	% Change		-4.07%	-0.38%	-0.45%	-1.90%	-2.39%	-1.44%	-0.11%	-1.76%	-0.67%	-0.60%	-0.30%
Apartment		81,111	81,324	82,417	83,775	83,730	80,592	87,673	103,029	126,328	150,019	146,131	146,720
	Change		213	1,093	1,358	(45)	(3,138)	7,081	15,356	23,299	23,691	(3,888)	589
	% Change		0.26%	1.34%	1.65%	-0.05%	-3.75%	8.79%	17.52%	22.61%	18.75%	-2.59%	0.40%
Commercial		17,713	17,476	17,500	17,456	17,311	17,061	17,100	17,614	18,271	19,604	19,186	19,044
	Change		(237)	24	(44)	(145)	(250)	39	514	657	1,333	(418)	(142)
	% Change		-1.34%	0.14%	-0.25%	-0.83%	-1.44%	0.23%	3.01%	3.73%	7.30%	-2.13%	-0.74%
Industrial		59,273	56,498	53,359	56,378	51,840	53,389	54,939	60,691	75,309	89,421	98,900	101,946
	Change		(2,775)	(3,139)	3,019	(4,538)	1,549	1,550	5,752	14,618	14,112	9,479	3,046
	% Change		-4.68%	-5.56%	5.66%	-8.05%	2.99%	2.90%	10.47%	24.09%	18.74%	10.60%	3.08%

* All historical average uses are on a calendar-year basis and have been normalized to the 2011 Budget degree days.

Witness: R. Lei

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010 Bridge Year Estimate	2011 Budget
Rate 1		3,047	2,923	2,912	2,899	2,844	2,776	2,736	2,733	2,685	2,667	2,651	2,643
	Change		(124)	(11)	(13)	(55)	(68)	(40)	(3)	(48)	(18)	(16)	(8)
	% Change	1.53%	-4.07%	-0.38%	-0.45%	-1.90%	-2.39%	-1.44%	-0.11%	-1.76%	-0.67%	-0.60%	-0.30%
Rate 6		22,168	21,787	21,698	21,839	21,502	21,165	21,546	22,979	25,353	28,051	28,051	28,029
	Change		(381)	(89)	141	(337)	(337)	381	1,433	2,374	2,698	0	(22)
	% Change	2.04%	-1.72%	-0.41%	0.65%	-1.54%	-1.57%	1.80%	6.65%	10.33%	10.64%	0.00%	-0.08%

* All historical average uses are on a calendar-year basis and have been normalized to the 2011 Budget degree days.

Witness: R. Lei

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	2,604	2,637	(33)	-1.3%
		Rate 6	27,281	28,165	(884)	-3.1%
		Total General Service	4,659	4,770	(111)	-2.3%
	2010**	Rate 1	2,619	2,622	(3)	-0.1%
		Rate 6	27,816	27,949	(133)	-0.5%
		Total General Service	4,699	4,705	(6)	-0.1%
	2011	Rate 1		2,643		
		Rate 6		28,029		
		Total General Service		4,726		

* 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.

**2010 Bridge Year Estimate was reported at column 1 because actual numbers are not available

LARGE VOLUME (CONTRACT) CUSTOMER DEMAND
HISTORICAL NORMALIZED ACTUAL AND BOARD APPROVED - FISCAL AND CALENDAR YEARS

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

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

CONTRACT CUSTOMERS NORMALIZED VOLUME

	Test Year	Col. 1 Actual Normalized Consumption (10^6m^3)	Col. 2 Board Approved Normalized Consumption (10^6m^3)	Col. 3 Variance Normalized Consumption (1-2)	Col. 4 %Variance Normalized Consumption (3/2)*100
FISCAL YEAR	2001	4,292.5	4,517.1	(224.6)	-5.0%
	2002	4,433.6	4,355.6	78.0	1.8%
	2003	4,380.7	4,400.2	(19.5)	-0.4%
	2004*	4,275.7	4,309.7	(34.0)	-0.8%
	2005	4,199.2	4,334.2	(135.0)	-3.1%
CALENDAR YEAR	2006	4,119.1	4,387.9	(268.8)	-6.1%
	2007	3,739.8	4,134.3	(394.5)	-9.5%
	2008	3,099.6	3,355.2	(255.6)	-7.6%
	2009	2,191.4	2,316.6	(125.2)	-5.4%
	2010**	2,061.7	2,008.6	53.1	2.6%
	2011		2,022.9		

* 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.

**2010 Bridge Year Estimate was reported at column 1 because actual numbers are not available

AVERAGE NUMBER OF CUSTOMERS

1. The purpose of this exhibit is to present the calculation of the 2011 annual average number of customers reported in the 2011 Revenue per Customer Cap formula at Exhibit B, Tab 1, Schedule 2. The annual average customer methodology used by the Company has been applied to calculate Board Approved annual average customer for more than ten years. All the information shown in this evidence is on a calendar-year basis (i.e., on a December fiscal year end basis) excluding the Historical Actual vs. Board Approved section. The Test Year Budget incorporates 2009 Actual and 2010 Bridge Year Estimate billing information.

2. The 2011 Customers Budget of 1,965,538 is forecast to be 29,802 or 1.5% above the 2010 Bridge Year Estimate of 1,935,736. The increase in customers is primarily attributable to the customer additions in the 2011 Budget. The total customer additions for the 2011 Budget are 36,237, which are described in detail in the evidence at Exhibit B, Tab 1, Schedule 4. The customer additions forecast underpins the new customer volumes of 89.5 10^6m^3 added between 2011 Budget and 2010 Estimate at Exhibit B, Tab 1, Schedule 5, page 5. The 2010 Bridge Year Estimate Customers Budget of 1,935,736 is 4,208 higher than the 2010 Board Approved Budget.

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

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

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 (2010 Estimate)
   + forecast new customer additions
   + forecast replacement customer additions
   - forecast lost customers
   + forecast transfer gains (i.e. customer migration from general service Rate 6 to contract market rate class)
   – forecast transfer losses (i.e. customer migration from contract market rate class to general service Rate 6)

5. The forecast of total number of general service customers is obtained by adding the forecast customer additions at Exhibit B, Tab 1, Schedule 4 along with a time lag between customer additions and unlock meters to the number of customers recorded at the end of the bridge year estimate. Historical average monthly change

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

forecast general service customers = year end customers (2010 Estimate)
*+ forecast new construction customer additions*new construction time lag*
*+ forecast replacement customer additions*replacement time lag*
+ historical average monthly change in actual lock customers
+ forecast transfer gains (i.e. customer migration from contract market rate class to general service Rate 6)
- forecast transfer losses (i.e. customer migration from general service Rate 6 to contract market rate class)

6. Lock meters are defined as customers whose gas meters are locked and no gas is flowing through the meter to a premise. These can result from vacant premises (e.g. new construction, move-in/move-out, bankruptcies, etc.), customers switching off gas to an alternate energy source, payment or credit reasons, and seasonal usage (e.g. cottage). The historical average of the past three years' monthly actual data is used in order to obtain a forecast of lock meters for the 2011 Budget. Table 1 on the following page, presents the past three years historical annual actual lock customer data.

Table 1 - Historical Annual Average Locks Customers

Calendar Year	Lock Customers
2007	33,240
2008	33,055
2009	35,044

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

8. Similar to lock customers, this time lag is challenging to predict. Therefore, the latest available historical actual data is used in order to obtain an objective forecast of lock meters for the budget. Table 2 on the following page, presents a summary of the 2011 budgeted time lag. It is expected the average time lag (i.e., number of months) for replacement customer additions will be shorter than new construction or subdivision customer additions. Also, the average time lag for commercial buildings or offices is anticipated to be longer than residential homes.

Table 2 - 2011 Budget Time Lag (i.e. Number of Months)

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

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

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

10. Table 3 on the following page, illustrates 16-Year of Historical Actual vs. Board Approved customer numbers. Overall, the average percentage error variances over the past 16 years were 952 customers or less than 0.1%. Overall, the existing methodology has continued to be a good predictor of actual customers.

11. The favourable customer numbers variance between 2010 Bridge Year Estimate and 2010 Board Approved Budget is primarily attributable to an increase in customer additions in 2010 Bridge Year Estimate.

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	1,887,605	1,906,437	(18,832)	-1.0%
	2010**	1,935,736	1,931,528	4,208	0.2%
	2011		1,965,538		

* 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.

**2010 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 2011[1].

2. The 2011 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 2011, the degree day forecasts are as follows:
   a. Central weather zone: 3,642 Environment Canada degree days; 3,602 Gas Supply degree days
   b. Eastern weather zone: 4,463 Environment Canada degree days; 4,421 Gas Supply degree days
   c. Niagara weather zone: 3,500 Environment Canada degree days; 3,447 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 2011. The model is estimated using data covering the period 1990 to 2009, a period of 20 years. Estimation results are provided in Figure 1.

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

4. The degree day forecast for the Eastern weather zone was prepared using the Energy Probe method. This method regresses actual Environment Canada degree days on a constant, a 5 year weighted average of Environment Canada degree days, a 5 year moving average of Environment Canada degree days and a trend[2]. The 5 year weighted averages and 5 year moving averages are lagged 2 years. Table 2 displays the actual Environment Canada degree day data for the Eastern weather zone, the 5 year weighted and moving averages and the trend data used to estimate the model. The resultant degree day forecast for 2011 is presented in Table 2 as well. The model is estimated over the period 1950 to 2009 a total of 60 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 1990 to 2009 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 1980 to 2009, 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.

Witnesses: I. McLeod
H. Sayyan

Table 1
Environment Canada Degree Day Forecast – Central

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	Actual[1]	Trend	Fitted[2]
1990	3,631	1	3,926
1991	3,686	2	3,912
1992	4,112	3	3,899
1993	4,180	4	3,885
1994	4,115	5	3,872
1995	4,040	6	3,858
1996	4,177	7	3,845
1997	4,026	8	3,831
1998	3,220	9	3,818
1999	3,539	10	3,804
2000	3,826	11	3,791
2001	3,420	12	3,777
2002	3,630	13	3,764
2003	3,982	14	3,750
2004	3,798	15	3,737
2005	3,797	16	3,723
2006	3,378	17	3,710
2007	3,722	18	3,696
2008	3,837	19	3,683
2009	3,836	20	3,669
2011 Forecast		22	3,642

[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	4,723
1951	4,587	2	4,622	4,594	4,703
1952	4,404	3	4,647	4,661	4,722
1953	4,059	4	4,657	4,641	4,706
1954	4,707	5	4,572	4,556	4,689
1955	4,689	6	4,467	4,385	4,638
1956	4,799	7	4,516	4,465	4,656
1957	4,405	8	4,489	4,523	4,688
1958	4,736	9	4,531	4,626	4,720
1959	4,718	10	4,532	4,584	4,695
1960	4,451	11	4,667	4,652	4,680
1961	4,586	12	4,669	4,669	4,683
1962	4,826	13	4,622	4,596	4,660
1963	4,921	14	4,579	4,584	4,664
1964	4,569	15	4,663	4,667	4,672
1965	4,810	16	4,701	4,753	4,697
1966	4,683	17	4,671	4,709	4,682
1967	4,882	18	4,743	4,755	4,677
1968	4,780	19	4,762	4,735	4,657
1969	4,698	20	4,773	4,775	4,668
1970	4,899	21	4,745	4,778	4,675
1971	4,797	22	4,771	4,762	4,655
1972	5,014	23	4,788	4,805	4,665
1973	4,420	24	4,811	4,808	4,655
1974	4,725	25	4,838	4,876	4,675
1975	4,514	26	4,766	4,736	4,628
1976	5,008	27	4,771	4,723	4,616
1977	4,597	28	4,694	4,637	4,596
1978	4,939	29	4,736	4,741	4,628
1979	4,589	30	4,652	4,695	4,629
1980	4,920	31	4,756	4,790	4,637
1981	4,438	32	4,729	4,735	4,615
1982	4,647	33	4,810	4,798	4,615
1983	4,536	34	4,697	4,674	4,589
1984	4,535	35	4,707	4,658	4,574
1985	4,659	36	4,626	4,601	4,569
1986	4,501	37	4,615	4,570	4,554
1987	4,328	38	4,563	4,585	4,574
1988	4,640	39	4,576	4,564	4,556
1989	4,931	40	4,512	4,482	4,534
1990	4,250	41	4,532	4,524	4,543
1991	4,303	42	4,612	4,657	4,577
1992	4,861	43	4,530	4,537	4,542
1993	4,780	44	4,490	4,461	4,515
1994	4,730	45	4,597	4,585	4,535
1995	4,585	46	4,625	4,646	4,551
1996	4,603	47	4,585	4,681	4,577
1997	4,786	48	4,652	4,680	4,551
1998	3,828	49	4,712	4,664	4,520
1999	4,137	50	4,697	4,689	4,532
2000	4,543	51	4,506	4,399	4,452
2001	4,115	52	4,387	4,276	4,428
2002	4,381	53	4,379	4,328	4,452
2003	4,715	54	4,282	4,240	4,437
2004	4,637	55	4,201	4,273	4,475
2005	4,421	56	4,378	4,444	4,495
2006	4,037	57	4,478	4,531	4,500
2007	4,447	58	4,454	4,511	4,495
2008	4,488	59	4,438	4,373	4,430
2009	4,534	60	4,451	4,376	4,423
2011 Forecast		62	4,385	4,430	4,463

[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]
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		3,697		
1990	3,307	1	3,705	3,599	3,652
1991	3,343	2	3,711	3,590	3,651
1992	3,759	3	3,697	3,582	3,640
1993	3,878	4	3,687	3,574	3,630
1994	3,780	5	3,692	3,565	3,628
1995	3,703	6	3,693	3,557	3,625
1996	3,786	7	3,701	3,548	3,625
1997	3,669	8	3,693	3,540	3,616
1998	2,980	9	3,704	3,531	3,618
1999	3,338	10	3,699	3,523	3,611
2000	3,596	11	3,670	3,515	3,592
2001	3,239	12	3,665	3,506	3,586
2002	3,415	13	3,659	3,498	3,578
2003	3,799	14	3,645	3,489	3,567
2004	3,632	15	3,631	3,481	3,556
2005	3,653	16	3,642	3,473	3,558
2006	3,163	17	3,639	3,464	3,552
2007	3,296	18	3,644	3,456	3,550
2008	3,480	19	3,619	3,447	3,510
2009	3,565	20	3,604	3,439	3,522
2011 Forecast		22	3,578	3,422	3,500

[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: 1990 2009 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4,600.6250	625.41	7.36	0.00
TREND	-13.4979	10.46	-1.29	0.21

R-squared	0.08	F-statistic	1.66
Adjusted R-squared	0.03	F-prob	0.21

Figure 2

Energy Probe Forecasting Equation and Test Statistics - Eastern

Sample: 1950 2009 Included observations: 60

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4,061.6140	1,231.47	3.30	0.00
ECEDD5WA	0.4758	0.71	0.67	0.50
ECEDD5MA	-0.3247	0.76	-0.43	0.67
@TREND	-3.9883	2.02	-1.98	0.05

R-squared	0.12	F-statistic	2.46
Adjusted R-squared	0.07	F-prob	0.07

Figure 3

20-Year Trend Forecasting Equation and Test Statistics - Niagara

Sample: 1990 2009 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4,019.6090	577.93	6.96	0.00
TREND	-8.4159	9.67	-0.87	0.40

R-squared	0.04	F-statistic	0.76
Adjusted R-squared	-0.01	F-prob	0.40

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 2011 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]
1990	3,631	3,574	3,592
1991	3,686	3,649	3,643
1992	4,112	3,989	4,041
1993	4,180	4,040	4,106
1994	4,115	4,084	4,045
1995	4,040	3,991	3,974
1996	4,177	4,133	4,102
1997	4,026	3,966	3,961
1998	3,220	3,202	3,207
1999	3,539	3,497	3,506
2000	3,826	3,784	3,774
2001	3,420	3,400	3,395
2002	3,630	3,597	3,591
2003	3,982	3,949	3,920
2004	3,798	3,766	3,748
2005	3,797	3,750	3,747
2006	3,378	3,355	3,356
2007	3,722	3,659	3,677
2008	3,837	3,801	3,784
2009	3,836	3,767	3,783
2011 Forecast	3,642		3,602

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

Gas Supply degree days = 196.3951+0.9351(Environment Canada degree days)

Witnesses: I. McLeod
H. Sayyan

Table 5
Determination of Gas Supply Equivalent Degree Days - Eastern

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	Actual Environment Canada Degree Days	Actual Gas Supply Degree Days	Fitted Gas Supply Degree Days [1]
1970	4,899	5,018	4,839
1971	4,797	4,584	4,742
1972	5,014	4,816	4,950
1973	4,420	4,480	4,380
1974	4,725	4,858	4,672
1975	4,514	4,229	4,470
1976	5,008	4,901	4,943
1977	4,597	4,604	4,549
1978	4,939	4,920	4,878
1979	4,589	4,550	4,542
1980	4,920	4,853	4,859
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	4,590
1989	4,931	4,883	4,870
1990	4,250	4,225	4,217
1991	4,303	4,270	4,268
1992	4,861	4,746	4,802
1993	4,780	4,715	4,725
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	4,730
1998	3,828	3,802	3,813
1999	4,137	4,112	4,109
2000	4,543	4,506	4,498
2001	4,115	4,071	4,088
2002	4,381	4,317	4,342
2003	4,715	4,663	4,662
2004	4,637	4,598	4,588
2005	4,421	4,397	4,381
2006	4,037	4,012	4,013
2007	4,447	4,411	4,406
2008	4,488	4,431	4,445
2009	4,534	4,472	4,489
2011 Forecast	4,463		4,421

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

Gas Supply degree days = 144.5404+0.9583(Environment Canada degree days)

Witnesses: I. McLeod
H. Sayyan

Table 6
Determination of Gas Supply Equivalent Degree Days - Niagara

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	Actual Environment Canada Degree Days	Actual Gas Supply Degree Days	Fitted Gas Supply Degree Days [1]
1985	3,651	3,649	3,567
1986	3,603	3,384	3,529
1987	3,441	3,600	3,399
1988	3,693	3,611	3,601
1989	3,845	3,599	3,723
1990	3,307	3,511	3,292
1991	3,343	3,287	3,321
1992	3,759	3,636	3,654
1993	3,878	3,667	3,750
1994	3,780	3,616	3,671
1995	3,703	3,577	3,609
1996	3,786	3,808	3,676
1997	3,669	3,646	3,582
1998	2,980	2,931	3,030
1999	3,338	3,277	3,317
2000	3,596	3,553	3,523
2001	3,239	3,162	3,238
2002	3,415	3,304	3,378
2003	3,799	3,688	3,686
2004	3,632	3,485	3,552
2005	3,653	3,580	3,569
2006	3,163	3,079	3,177
2007	3,296	3,349	3,283
2008	3,480	3,510	3,431
2009	3,565	3,547	3,498
2011 Forecast	3,500		3,447

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

Gas Supply degree days = 643.7269+0.8009(Environment Canada degree days)

Witnesses: I. McLeod
H. Sayyan

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 2011[2] revenue class 20 is forecast to comprise 86% of Rate 1 volumes while revenue classes 12, 48 and 73 are forecast to collectively comprise 93% of Rate 6 volumes. Volumes for the remaining revenue classes in Rate 1 are forecast to comprise 14% of Rate 1 volumes while the remaining revenue classes in Rate 6 are forecast to comprise 7% of Rate 6 volumes.

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

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

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

4. The year-over-year growth rates in average use for all revenue classes are used to compute the average use forecast for Rate 1 and Rate 6. Factors influencing overall average use include new customers (both new construction and replacement customers), the timing of new customer additions to the system, rate migration, gas prices, economic conditions and the Company's DSM programs. Refer to Exhibit 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 are valid and produce accurate forecasts of general service average use.

<u>Error Correction Model</u>

6. The Company uses the Error Correction Model ("ECM") to forecast the average use for Rate 1 and Rate 6. The Error Correction Model and the two step estimation

procedure are described more fully in Engle and Granger (1987).[3] The error correction model uses the concept of cointegration or long-run association between variables. In other words, variables hypothesized to be linked by some theoretical economic relationship should not diverge from each other in the long run. Such variables may drift apart in the short run, however, if they were to diverge without bound, an equilibrium relationship among such variables could not be said to exist. The ECM methodology has been used extensively in the energy field for modeling electricity sales[4] and natural gas prices[5].

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

8. The estimation 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 2011.

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

Witnesses: I. McLeod
H. Sayyan

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 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 2009. Out-of-sample, or ex-ante, means that the model incorporates only a portion of the sample, in this case 1985 to 2007. Forecasts of average use are produced under both approaches and measured against actual average use from 2008 to 2009 quantitatively via MPE and RMSPE. A two year "hold out" sample is used to compute the in-sample and out-of-sample forecast accuracy statistics since the forecasting horizon for budgeting purposes is two years. Table 1 presents the forecast accuracy statistics for Rate 1 and Rate 6. The smaller the MPE and RMSPE, the better 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)	1.07%	-1.12%
In-Sample RMSPE (2 Years)	1.31%	1.25%
Out-of-Sample % Variance (2 Years)	4.64%	-12.78%
Out-of-Sample RMSPE (2 Years)	4.73%	13.43%

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

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

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

Witnesses: I. McLeod
H. Sayyan

TABLE 2

RATE 1 IN-SAMPLE FORECAST COMPARISON

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

[1]Board approved normalized average use from RP-2000-0040, RP-2001-0032, RP-2002-0133, RP-2003-0203, EB-2005-0001, EB-2006-0034, EB-2007-0615 and EB-2008-0219 for 2001, 2002, 2003, 2005, 2006, 2007, 2008 and 2009 respectively.

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

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

Witnesses: I. McLeod
H. Sayyan

TABLE 3
RATE 6 IN-SAMPLE FORECAST COMPARISON

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

[1]Board approved normalized average use from RP-2000-0040, RP-2001-0032, RP-2002-0133, RP-2003-0203, EB-2005-0001, EB-2006-0034, EB-2007-0615 and EB-2008-0219 for 2001, 2002, 2003, 2005, 2006, 2007, 2008 and 2009 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

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

[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.

Ramsey RESET Test

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

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

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

TABLE 4 - RATE 1 MODEL MNEMONICS

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

TABLE 5 CONTINUED - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Northern Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.93	1.10	0.28
LOG(CDD)	0.70	18.36	0.00
LOG(REALCRCRPG)	-0.11	-6.09	0.00
LOG(NOR20VINT)	0.26	7.67	0.00
LOG(CENTEMP)	0.19	2.09	0.05
DUM2009	-0.05	-3.28	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	433.92		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.78	0.45
DLOG(CDD)	0.71	22.19	0.00
DLOG(REALCRCRPG)	-0.06	-1.79	0.09
DLOG(NOR20VINT)	0.28	2.56	0.02
DUM2009	-0.04	-2.71	0.02
AR(1)	-0.43	-1.31	0.21
ECM_NOR20(-1)	-0.71	-2.20	0.04
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	98.26		0.00

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.61	4.72	0.00
LOG(EDD)	0.78	18.68	0.00
LOG(REALERCRPG)	-0.06	-4.05	0.00
LOG(ERC20VINT)	0.24	16.88	0.00
DUM2008	-0.04	-4.14	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	454.92		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.73	0.01
DLOG(EDD)	0.78	21.93	0.00
DLOG(REALERCRPG)	-0.06	-2.24	0.04
DUM2008	-0.02	-1.77	0.09
ECM_ERC20(-1)	-0.79	-2.91	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	132.82		0.00

Niagara Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.38	5.40	0.00
LOG(NDD)	0.70	12.72	0.00
LOG(TIME)	-0.03	-2.10	0.05
LOG(REALNRCRPG)	-0.10	-2.93	0.01
LOG(NRC20VINT)	0.43	2.31	0.03
DUM2008	-0.07	-3.92	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	179.44		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-3.12	0.01
DLOG(NDD)	0.71	22.35	0.00
DLOG(REALNRCRPG)	-0.06	-2.12	0.05
DUM2008	-0.03	-2.42	0.03
ECM_NRC20(-1)	-0.56	-2.88	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	143.78		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	0.46	0.02	0.95	0.02	0.89	0.21
	P Value	0.50	0.89	0.33	0.89	0.35	0.64
ARCH Test	Test Statistic	0.13	0.01	0.45	1.04	0.05	0.18
	P Value	0.72	0.93	0.50	0.31	0.82	0.67
Chow Forecast Test: Forecast from 2009 to 2009	Test Statistic	0.76	1.54	1.36	7.37*	2.71	0.23
	P Value	0.40	0.23	0.24	0.02	0.12	0.64
Ramsey RESET Test	Test Statistic	1.25	1.00	0.05	0.09	0.34	0.25
	P Value	0.28	0.33	0.83	0.77	0.57	0.62

*without dum2009

Witnesses: I. McLeod
H. Sayyan

TABLE 7 - RATE 6 MODEL MNEMONICS

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

Witnesses: I. McLeod
H. Sayyan

TABLE 8 - RATE 6 REVENUE CLASS 12 REGRESSION EQUATIONS

Central Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	0.32	0.19	0.85
LOG(CDD)	0.58	5.34	0.00
LOG(REALCRCCPG)	-0.11	-1.80	0.09
LOG(CENTEMP)	0.81	5.03	0.00
DUM1996	-0.11	-4.65	0.00
DUMCRC12	0.26	6.20	0.00
AR(1)	0.26	1.08	0.30
R-squared	0.96		
Adjusted R-squared	0.94		
S.E. of regression	0.04		
F-statistic	65.885		0.00

Eastern Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	3.93	2.89	0.01
LOG(EDD)	0.54	9.19	0.00
LOG(TIME)	-0.05	-3.82	0.00
LOG(REALERCCPG)	-0.12	-2.65	0.02
LOG(EASTEMP)	0.40	2.13	0.05
DUMERC12	0.22	9.86	0.00
DUM2009	0.13	4.94	0.00
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	111.73		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.18	0.04
DLOG(EDD)	0.57	12.93	0.00
DLOG(REALERCCPG)	-0.13	-3.88	0.00
DLOG(EASTEMP)	0.67	3.06	0.01
DUMERC12	0.22	12.23	0.00
DUM2009	-0.08	-3.30	0.00
ECM_ERC12(-1)	-0.91	-3.62	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	82.85		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
DUM2009	-0.07	-3.05	0.01
R-squared	0.91		
Adjusted R-squared	0.88		
S.E. of regression	0.02		
F-statistic	30.75		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
DUM2009	-0.05	-2.50	0.02
ECM_NRC12(-1)	-0.98	-3.95	0.00
R-squared	0.94		
Adjusted R-squared	0.91		
S.E. of regression	0.02		
F-statistic	42.10		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	0.02	0.03	0.98
LOG(CDD)	0.89	15.64	0.00
LOG(TIME)	-0.12	-9.15	0.00
LOG(CRCCOMVAC)	-0.07	-4.80	0.00
LOG(ONTGDP)	0.25	4.25	0.00
DUM2009	0.08	4.25	0.00
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	146.35		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.42	0.68
DLOG(CDD)	0.87	30.08	0.00
DLOG(TIME)	-0.07	-3.75	0.00
DLOG(CRCCOMVAC)	-0.06	-4.20	0.00
DLOG(ONTGDP)	0.11	0.96	0.35
DUM2009	0.07	5.00	0.00
ECM_CRC48(-1)	-0.91	-5.49	0.00
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	161.26		0.00

Eastern Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.67	1.71	0.10
LOG(EDD)	0.74	10.04	0.00
LOG(TIME)	-0.16	-13.86	0.00
LOG(ONTGDP)	0.19	3.93	0.00
DUMERC48	0.10	5.65	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	165.78		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.16	0.87
DLOG(EDD)	0.79	20.11	0.00
DLOG(TIME)	-0.10	-4.55	0.00
DUMERC48	0.04	3.75	0.00
ECM_ERC48(-1)	-0.98	-5.61	0.00
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	0.02		
F-statistic	119.80		0.00

Niagara Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.81	-0.52	0.61
LOG(NDD)	0.70	11.64	0.00
LOG(TIME)	-0.09	-4.66	0.00
LOG(REALNRCCPG)	-0.17	-4.26	0.00
LOG(ONTGDP)	0.39	3.62	0.00
DUM2009	0.12	5.34	0.00
R-squared	0.93		
Adjusted R-squared	0.91		
S.E. of regression	0.02		
F-statistic	51.42		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.16	0.04
DLOG(NDD)	0.72	16.62	0.00
DLOG(ONTGDP)	0.39	2.29	0.03
DUM2009	0.16	6.85	0.00
ECM_NRC48(-1)	-0.82	-3.39	0.00
R-squared	0.95		
Adjusted R-squared	0.94		
S.E. of regression	0.02		
F-statistic	97.33		0.00

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	2.95	2.01	0.06
LOG(CDD)	0.36	3.46	0.00
LOG(TIME)	-0.16	-8.97	0.00
LOG(ONTGDP)	0.42	5.83	0.00
DUMCRC73	0.35	13.13	0.00
AR(1)	-0.40	-1.85	0.08
R-squared	0.91		
Adjusted R-squared	0.89		
S.E. of regression	0.04		
F-statistic	38.560		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.23	0.82
DLOG(CDD)	0.51	8.64	0.00
DLOG(ONTGDP)	0.43	1.98	0.06
DLOG(TIME)	-0.16	-3.98	0.00
DUMCRC73	0.24	8.32	0.00
DUM2009	-0.13	-3.00	0.01
ECM_CRC73(-1)	-0.91	-5.08	0.00
R-squared	0.93		
Adjusted R-squared	0.91		
S.E. of regression	0.03		
F-statistic	37.86		0.00

Eastern Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-196,900.40	-1.85	0.08
EDD	15.85	0.94	0.36
TIME	-5,634.14	-4.67	0.00
EASTEMP	565.34	3.53	0.00
DUM2003	72,800.73	3.88	0.00
DUM2004	-166,656.80	-7.17	0.00
DUMERC73	81,403.99	5.25	0.00
R-squared	0.88		
Adjusted R-squared	0.84		
S.E. of regression	16,126.11		
F-statistic	22.11		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-3,211.79	-0.51	0.61
D(EDD)	19.28	1.08	0.30
D(EASTEMP)	885.73	1.68	0.11
DUM2003	60,192.36	2.15	0.05
DUM2004	-227,088.60	-5.76	0.00
DUMERC73	33,870.68	1.71	0.11
ECM_ERC73(-1)	-1.14	-1.95	0.07
R-squared	0.85		
Adjusted R-squared	0.80		
S.E. of regression	22,828.60		
F-statistic	16.04		0.00

Niagara Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-3.86	-0.68	0.51
LOG(NDD)	0.61	1.59	0.13
LOG(TIME)	-0.14	-2.02	0.06
LOG(REALNRCCPG)	-0.12	-0.88	0.39
LOG(MANUFACTURING)	0.93	2.56	0.02
DUM2002	-0.35	-2.57	0.02
DUMNRC73	0.68	6.14	0.00
R-squared	0.78		
Adjusted R-squared	0.71		
S.E. of regression	0.13		
F-statistic	10.93		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-0.27	0.79
DLOG(NDD)	0.81	3.32	0.00
DLOG(MANUFACTURING)	1.01	2.07	0.05
DUM2002	-0.40	-3.22	0.00
DUMNRC73	0.29	3.25	0.00
ECM_NRC73(-1)	-0.47	-1.74	0.10
R-squared	0.75		
Adjusted R-squared	0.69		
S.E. of regression	0.11		
F-statistic	11.01		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	2.50	0.01	2.67	1.55	1.37	0.04	0.02	0.31	0.44
	P Value	0.11	0.94	0.10	0.21	0.24	0.85	0.89	0.58	0.51
ARCH Test	Test Statistic	1.01	1.11	0.12	0.12	0.22	0.47	0.44	0.10	0.93
	P Value	0.32	0.29	0.73	0.73	0.64	0.50	0.51	0.75	0.33
Chow Forecast Test: Forecast from 2009 to 2009	Test Statistic	2.01	10.86*	6.24*	25.00*	2.70	46.98*	8.98*	0.02	0.38
	P Value	0.18	0.00	0.02	0.00	0.12	0.00	0.01	0.90	0.55
Ramsey RESET Test	Test Statistic	1.79	1.25	3.04	0.32	2.74	0.07	3.30	0.02	0.59
	P Value	0.20	0.28	0.10	0.58	0.12	0.80	0.09	0.90	0.45

*without dum2009

Witnesses: I. McLeod
H. Sayyan

14. Driver variable assumptions are presented in Table 10 in year over year growth rates. Major driver variables in the models are balance point heating degree days adjusted for billing cycles, vintage, time trend, real natural gas prices and economic variables. The driver variable assumptions are based on economic assumptions from the Economic Outlook, Spring 2010.

15. Natural gas prices have an impact on average use. Sharp increases can typically have two effects. Firstly, they can influence customers' fuel use habits, for example, the lowering of thermostat settings. Secondly, price increases can factor in customers' decision-making around the purchase of more efficient furnaces and other appliances. In addition, homeowners may also respond by retrofitting older residences in order to reduce energy consumption. In the models, real natural gas prices are used. The Consumer Price Index ("CPI") is used to convert nominal gas prices to real gas prices. Nominal energy price forecasts are based on the PIRA Henry Hub price forecast produced in May 2010.

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

17. The vintage variable (for revenue class 20 only) is employed as a proxy measure of gas space heating and gas water heating efficiency gains and residential thermal efficiency. Newer homes with improved thermal envelope characteristics and older homes adding insulation and storm windows/doors reduce the typical amount of gas needed for space heating. Residential thermal efficiency will

continue to improve as newer, better-insulated residences account for a larger portion of the housing stock. The vintage variable captures the impact of both furnace efficiency and new home thermal efficiency on average use.

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

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

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

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

[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.

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	2005	2006	2007	2008	2009	2010F	2011F
REAL GDP (% CHANGE)							
CANADA	3.0	2.9	2.5	0.4	-2.6	3.2	3.0
U.S.	3.1	2.7	2.1	0.4	-2.4	3.2	3.0
REAL EXPORTS (% CHANGE)	1.9	0.8	1.1	-4.7	-14.0	6.6	5.6
REAL IMPORTS (% CHANGE)	7.1	4.7	5.8	0.8	-13.4	8.5	6.0
HOUSING STARTS (000's)	225	227	228	211	149	181	180
UNEMPLOYMENT RATE (%)	6.8	6.3	6.0	6.1	8.3	8.2	7.8
EMPLOYMENT GROWTH (% CHANGE)	1.4	1.9	2.3	1.5	-1.6	1.1	1.8
CONSUMER PRICES (% CHANGE)							
CANADA	2.2	2.0	2.1	2.4	0.3	1.8	2.1
U.S.	3.4	3.2	2.9	3.8	-0.4	2.0	2.0

TABLE-10 CONTINUED
Economic Outlook

ONTARIO

CALENDAR YEAR	2005	2006	2007	2008	2009	2010F	2011F
REAL GDP (% CHANGE)	2.8	2.4	2.3	-0.5	-3.4	3.2	3.2
REAL MANUFACTURING OUTPUT (% CHANGE)	0.4	-2.4	-2.7	-8.0	-13.7	7.5	6.2
HOUSING STARTS (000's)	78.8	73.4	68.1	75.1	50.4	61.5	63.2
UNEMPLOYMENT RATE (%)	6.6	6.3	6.4	6.5	9.0	9.0	8.4
EMPLOYMENT GROWTH (% CHANGE)	1.4	1.5	1.6	1.4	-2.4	1.2	2.1
CONSUMER PRICES (% CHANGE)	2.2	1.8	1.8	2.3	0.4	2.1	2.2
RETAIL SALES (% CHANGE)	4.8	4.1	3.9	3.5	-2.4	4.2	5.2
WAGE RATE (% CHANGE)	4.7	5.0	4.7	4.4	0.0	4.1	3.9
REAL RESIDENTIAL NATURAL GAS PRICE (% CHANGE)	8.8	8.9	-11.4	1.5	-17.8	-15.6	-4.2
REAL COMMERCIAL NATURAL GAS PRICE (% CHANGE)	10.1	10.0	-12.7	1.6	-19.8	-17.3	-5.2

TABLE-10 CONTINUED
Economic Outlook

REGIONS

CALENDAR YEAR	2005	2006	2007	2008	2009	2010F	2011F
GTA							
HOUSING STARTS (000's)	43.0	38.8	35.7	42.4	25.8	32.6	34.6
SINGLES	17.7	15.9	16.1	11.9	8.4	11.6	12.7
MULTIPLES	25.4	22.9	19.7	30.4	17.4	20.9	22.0
CONSUMER PRICES (% CHANGE)	1.9	1.6	1.9	2.4	0.5	2.0	2.1
UNEMPLOYMENT RATE (%)	6.8	6.3	6.5	6.6	9.0	9.3	8.6
EMPLOYMENT GROWTH (% CHANGE)	1.8	1.8	2.0	1.8	-1.6	1.8	3.3
COMMERCIAL VACANCY RATE (%)	9.3	7.3	6.3	5.4	6.9	7.9	7.9
INDUSTRIAL VACANCY RATE (%)	4.9	5.1	5.4	5.9	7.0	6.2	6.2
VINTAGE METRO REGION CENTRAL WEATHER ZONE (% CHANGE)	-1.1	-1.1	-1.8	-0.9	-0.9	-0.9	-0.9
VINTAGE WESTERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-3.3	-2.5	-2.7	-2.1	-2.1	-2.0	-1.9
VINTAGE CENTRAL REGION CENTRAL WEATHER ZONE (% CHANGE)	-3.6	-3.8	-3.1	-2.7	-2.7	-2.6	-2.5
VINTAGE NORTHERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-3.7	-3.8	-3.6	-3.1	-3.1	-2.9	-2.8
EASTERN							
HOUSING STARTS (000's)	5.2	6.1	6.8	7.2	6.0	7.0	7.3
SINGLES	2.5	2.7	3.1	3.1	2.6	3.3	3.2
MULTIPLES	2.6	3.4	3.6	4.1	3.4	3.7	4.1
CONSUMER PRICES (% CHANGE)	2.3	1.7	1.9	2.2	0.6	1.9	2.1
UNEMPLOYMENT RATE (%)	6.7	5.4	5.7	4.9	6.0	6.5	6.2
EMPLOYMENT GROWTH (% CHANGE)	1.7	3.2	1.2	3.4	-1.7	1.2	1.8
VINTAGE EASTERN WEATHER ZONE (% CHANGE)	-3.0	-2.7	-2.8	-3.1	-3.1	-2.9	-2.8
NIAGARA							
HOUSING STARTS (000's)	1.5	1.4	1.3	1.3	1.0	1.3	1.3
SINGLES	1.1	0.9	0.9	0.8	0.7	0.8	0.8
MULTIPLES	0.4	0.4	0.4	0.5	0.3	0.4	0.5
UNEMPLOYMENT RATE (%)	7.0	6.4	6.8	7.2	10.2	10.0	8.5
EMPLOYMENT GROWTH (% CHANGE)	3.1	-1.2	1.4	2.6	-6.0	3.1	2.2
VINTAGE NIAGARA WEATHER ZONE (% CHANGE)	-1.4	-1.2	-1.1	-1.1	-1.1	-1.1	-1.0

Witnesses: I. McLeod
H. Sayyan

TABLE-10 CONTINUED
Economic Outlook

INTEREST RATE & EXCHANGE RATE FORECAST

CALENDAR YEAR		2005	2006	2007	2008	2009	2010F	2011F
Canada								
Interest Rates	Overnight Rate	2.67	4.06	4.35	2.96	0.40	0.77	2.67
	Bank Rate	2.92	4.31	4.60	3.21	0.65	0.71	2.15
	Prime Rate	4.42	5.81	6.10	4.73	2.40	2.46	3.90
	1 Year Mortgage Rate	5.06	6.28	6.90	6.70	4.02	4.19	5.83
	3 Year Mortgage Rate	5.59	6.45	7.09	6.87	4.57	4.98	6.47
	5 Year Mortgage Rate	5.99	6.66	7.07	7.06	5.63	6.30	7.41
Money Markets	1 Month T-Bills	2.56	3.93	4.05	2.24	0.25	0.33	1.63
	3 Month T-Bills	2.73	4.04	4.12	2.30	0.32	0.81	2.54
	6 Month T-Bills	2.87	4.12	4.26	2.46	0.41	1.08	2.53
	1 Year T-Bills	3.09	4.19	4.32	2.56	0.61	1.12	2.57
	1 Month Bankers Acceptance	2.74	4.13	4.51	3.04	0.42	0.50	1.80
	3 Month Bankers Acceptance	2.84	4.19	4.57	3.08	0.42	0.59	1.90
	1 Month Commercial Paper	2.75	4.15	4.57	3.17	0.65	0.51	1.76
	3 Month Commercial Paper	2.84	4.21	4.63	3.23	0.65	0.61	1.90
Benchmark Government Bond Yields	2 Year	3.21	4.05	4.19	2.62	1.27	1.81	3.20
	3 Year	3.35	4.08	4.21	2.79	1.75	2.28	3.55
	5Year	3.59	4.12	4.22	3.01	2.41	2.98	3.36
	7 Year	3.81	4.16	4.24	3.26	2.67	3.29	3.92
	10Year	4.05	4.22	4.28	3.58	3.29	3.77	4.26
	30 Year	4.40	4.28	4.32	4.05	3.90	4.25	4.49
United States								
Interest Rates	Federal Funds Rate	3.25	5.02	5.00	1.86	0.13	0.28	1.88
	Prime Rate	6.19	7.96	8.05	5.09	3.25	3.29	4.12
	30 Year Mortgage Rate	5.87	6.41	6.34	6.04	5.04	5.13	5.86
Money Markets	1 Month T-Bills	3.00	4.75	4.40	1.29	0.10	0.16	1.11
	3 Month T-Bills	3.21	4.85	4.47	1.39	0.15	0.27	1.89
	6 Month T-Bills	3.50	4.99	4.61	1.66	0.28	0.68	2.08
	1 Month Non-Financial Commercial Paper	3.24	4.97	5.02	1.98	0.18	0.23	1.26
	3 Month Non-Financial Commercial Paper	3.40	5.03	4.99	2.12	0.26	0.27	1.31
	1 Month Financial Commercial Paper	3.27	5.00	5.07	2.38	0.26	0.25	1.19
	3 Month Financial Commercial Paper	3.44	5.06	5.13	2.64	0.42	0.32	1.36
Treasury Bond Yields	1 Year	3.62	4.93	4.52	1.82	0.47	0.36	1.55
	2 Year	3.85	4.82	4.36	2.00	0.96	0.82	2.37
	3 Year	3.93	4.77	4.34	2.24	1.43	1.45	3.21
	5 Year	4.05	4.75	4.43	2.80	2.19	2.44	3.86
	7 Year	4.15	4.76	4.50	3.17	2.81	3.20	4.36
	10 Year	4.29	4.79	4.63	3.67	3.26	3.81	4.75
	20 Year	4.65	4.99	4.91	4.36	4.11	5.18	5.01
	30 Year	4.60	4.87	4.83	4.28	4.07	4.72	5.11
Exchange Rate	$CDN/$US	1.21	1.13	1.07	1.06	1.14	1.01	1.03
	$US/$CDN	0.83	0.88	0.94	0.94	0.88	0.99	0.97

Witnesses: I. McLeod
H. Sayyan

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

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

Witnesses: I. McLeod
H. Sayyan

Conclusion

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

Witnesses: I. McLeod
H. Sayyan

Y FACTOR POWER GENERATION PROJECTS

1. Enbridge Gas Distribution ("Enbridge") has two new power generation pipeline projects budgeted for 2011. Table 1 on the following page, 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, and Board approval for construction commencement in 2010 was received on April 5, 2010. The York Energy Centre LP project was itself delayed in 2010, thus delaying the Enbridge pipeline build as well. The Enbridge project is currently in the material procurement phase. Pending Board approval to commence construction in 2011, construction is currently forecast to begin Q1 2011 with gas delivery after December 2011 completion.

3. The Greenfield South power generation facility has a contract with the Ministry of Energy. To date, Enbridge has not executed a gas delivery agreement with Greenfield South. 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 on the following page. The 2011 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 2011 which were not included within 2007 base rates, namely the Portlands Energy Centre put in service in 2008 and Thorold Cogen which was put in service in September 2009, are included within the Appendix A revenue requirement.

Table 1
Summary of 2011 Power Generation Related Projects

Facility	York Energy Centre Pipeline Project	Greenfield South Pipeline Project
Location	Township of King	Mississauga
Proposed Completion Date	December 2011	2012 [2]
Pipe Size and Length	NPS 16, 16.7 km	NPS 12, 650 m
2011 Budget	$30.8 -M [1]	$1.1-M
Total Forecast Budget	$39.1-M [1]	$2.0-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 2011 Budget of $21.1.-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: J. Sim
S. Murray

CAPITAL STRUCTURE
POWER GENERATION Y-FACTOR CALCULATION

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

	($000's)	2008	2009	2010	2011
7.	Ontario Utility Income	43.6	(269.3)	(394.7)	(499.7)
8.	Rate base	9,935.3	24,701.5	27,791.2	26,586.7
9.	Indicated rate of return	0.44 %	(1.09)%	(1.42)%	(1.88)%
10.	(Def.) / suff. in rate of return	(7.14)%	(8.67)%	(9.00)%	(9.46)%
11.	Net (def.) / suff.	(709.4)	(2,141.6)	(2,501.2)	(2,515.1)
12.	Gross (def.) / suff.	(1,066.8)	(3,196.4)	(3,624.9)	(3,505.4)

RATE BASE
POWER GENERATION Y-FACTOR CALCULATION

($000's)

Line No.		2008	2009	2010	2011
	Property, plant, and equipment				
1.	Cost or redetermined value	10,065.7	25,569.0	29,824.4	29,848.4
2.	Accumulated depreciation	(130.4)	(867.5)	(2,033.2)	(3,261.7)
3.		9,935.3	24,701.5	27,791.2	26,586.7
	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	9,935.3	24,701.5	27,791.2	26,586.7

INCOME
POWER GENERATION Y-FACTOR CALCULATION

($000's)

Line No.		2008	2009	2010	2011
	Revenue				
1.	Gas sales	-	-	-	-
2.	Transportation of gas	-	-	-	-
3.	Transmission and compression	-	-	-	-
4.	Other operating revenue	-	-	-	-
5.	Other income	-	-	-	-
6.	Total revenue	-	-	-	-
	Costs and expenses				
7.	Gas costs	-	-	-	-
8.	Operation and Maintenance	-	-	-	-
9.	Depreciation and amortization	355.6	1,063.8	1,227.9	1,228.8
10.	Municipal and other taxes	45.6	55.3	17.3	-
11.	Total costs and expenses	401.2	1,119.1	1,245.2	1,228.8
12.	**Utility income before inc. taxes**	(401.2)	(1,119.1)	(1,245.2)	(1,228.8)
	Income taxes				
13.	Excluding interest shield	(297.4)	(488.7)	(468.8)	(396.4)
14.	Tax shield on interest expense	(147.4)	(361.1)	(381.7)	(332.7)
15.	Total income taxes	(444.8)	(849.8)	(850.5)	(729.1)
16.	**Ontario utility net income**	43.6	(269.3)	(394.7)	(499.7)

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

($000's)

Line No.		2008	2009	2010	2011
1.	Utility income before income taxes	(401.2)	(1,119.1)	(1,245.2)	(1,228.8)
	Add Backs				
2.	Depreciation and amortization	355.6	1,063.8	1,227.9	1,228.8
3.	Large corporation tax	-	-	-	-
4.	Other non-deductible items	-	-	-	-
5.	Any other add back(s)	-	-	-	-
6.	Total added back	355.6	1,063.8	1,227.9	1,228.8
7.	Sub total - pre-tax income plus add backs	(45.6)	(55.3)	(17.3)	-
	Deductions				
8.	Capital cost allowance - Federal	476.0	1,080.8	1,174.3	1,104.9
9.	Capital cost allowance - Provincial	476.0	1,080.8	1,174.3	1,104.9
10.	Items capitalized for regulatory purposes	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-
13.	Amortization of cumulative eligible capital	366.0	344.9	320.7	298.3
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-
15.	Any other deduction(s)	-	-	-	-
16.	Total Deductions - Federal	842.0	1,425.7	1,495.0	1,403.2
17.	Total Deductions - Provincial	842.0	1,425.7	1,495.0	1,403.2
18.	Taxable income - Federal	(887.6)	(1,481.0)	(1,512.3)	(1,403.2)
19.	Taxable income - Provincial	(887.6)	(1,481.0)	(1,512.3)	(1,403.2)
20.	Income tax provision - Federal	(173.1)	(281.4)	(272.2)	(231.5)
21.	Income tax provision - Provincial	(124.3)	(207.3)	(196.6)	(164.9)
22.	Income tax provision - combined	(297.4)	(488.7)	(468.8)	(396.4)
23.	Part V1.1 tax	-	-	-	-
24.	Investment tax credit	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(297.4)	(488.7)	(468.8)	(396.4)
	Tax shield on interest expense				
26.	Rate base as adjusted	9,935.3	24,701.5	27,791.2	26,586.7
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	440.1	1,094.3	1,231.2	1,177.8
29.	Combined tax rate	33.500%	33.000%	31.000%	28.250%
30.	Income tax credit	(147.4)	(361.1)	(381.7)	(332.7)
31.	**Total income taxes**	(444.8)	(849.8)	(850.5)	(729.1)

REVENUE REQUIREMENT
POWER GENERATION Y-FACTOR CALCULATION

Line No.	($000's)	2008	2009	2010	2011
	Cost of capital				
1.	Rate base	9,935.3	24,701.5	27,791.2	26,586.7
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	753.1	1,872.4	2,106.6	2,015.3
	Cost of service				
4.	Gas costs	-	-	-	-
5.	Operation and Maintenance	-	-	-	-
6.	Depreciation and amortization	355.6	1,063.8	1,227.9	1,228.8
7.	Municipal and other taxes	45.6	55.3	17.3	-
8.	Cost of service	401.2	1,119.1	1,245.2	1,228.8
	Misc. & Non-Op. Rev				
9.	Other operating revenue	-	-	-	-
10.	Other income	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-
	Income taxes on earnings				
12.	Excluding tax shield	(297.4)	(488.7)	(468.8)	(396.4)
13.	Tax shield provided by interest expense	(147.4)	(361.1)	(381.7)	(332.7)
14.	Income taxes on earnings	(444.8)	(849.8)	(850.5)	(729.1)
	Taxes on (def) / suff.				
15.	Gross (def.) / suff.	(1,066.8)	(3,196.4)	(3,624.9)	(3,505.4)
16.	Net (def.) / suff.	(709.4)	(2,141.6)	(2,501.2)	(2,515.1)
17.	Taxes on (def.) / suff.	357.4	1,054.8	1,123.7	990.3
18.	**Revenue requirement**	1,066.9	3,196.5	3,625.0	3,505.3
	Revenue at existing Rates				
19.	Gas sales	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.1	0.1	0.1	(0.1)
23.	Revenue at existing rates	0.1	0.1	0.1	(0.1)
24.	**Gross revenue (def.) / suff.**	(1,066.8)	(3,196.4)	(3,624.9)	(3,505.4)

Y FACTORS - DSM PROGRAM

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

2. The DSM Y-factor amount included in the 2011 IR distribution revenue is $26.7 million approved by the Board in its Decision in the EB-2010-0175 Natural Gas DSM Plan proceeding dated September 24, 2010. The amount is shown at Exhibit B, Tab 1, Schedule 2, page 1, Column 1, Row 20.

3. As directed by the Board in the EB-2010-0175 Decision, any further amount for low income programs will be examined as part of that application. This is a result of the fact that Enbridge has not adjusted its 2011 DSM Budget to incorporate the proposed Low-Income Energy Assistance Program ("LEAP") funding at the level of 0.12% of the distribution revenue requirement ("DRR") in advance of any finding either in the consultative currently underway or a Board decision on the matter.

4. The Board's Decision in the EB-2010-0175 proceeding (September 24, 2010) stated;

> The Board expects Enbridge to file an amendment to the 2011 DSM plan which recognizes the government's policy with respect to increased conservation programs for low income consumers as expeditiously as possible. Furthermore, the Board expects that Enbridge will continue to consult on the plan amendments with all members of the consultative group and the Board also expects stakeholder involvement in initiating low income DSM programs.
>
> In the plan amendment, Enbridge may request additional funds for low-income programs, should it choose to do so. Any request for additional funding will be examined as part of that application. No other expansion of the DSM budget, other than for low income programs, will be considered.

Witness: K. Culbert

Y FACTORS – CIS CUSTOMER CARE COST

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

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

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

3. The amount recoverable for CIS/Customer Care costs is $ 97.4 million in the 2011 fiscal year.

Y FACTORS – GAS COST & CARRYING COSTS

1. This evidence supports the Company's Y-factor adjustment for 2011 gas cost and gas in storage related carrying costs.

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

   a. Incremental gas costs associated with upstream transportation, storage and supply mix costs relative to the Company's 2011 volumetric forecast. The Company's current 2011 forecast of gas costs to operations is found at Exhibit B, Tab 4, Schedules 1 and 2. Additionally, an adjustment is required to allow for the change in revenue requirement 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 2010 forecast costs from rates and replace them with the costs associated with the 2011 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.

3. The amount recoverable for carrying costs related to gas in storage for the 2011 fiscal year is $30.9 million.

Witness: K. Culbert

2011 PROPOSED RATES

1. This evidence outlines the Company's proposal with respect to 2011 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 2011 rates including the proposed recovery of the 2011 revenue requirement.

2. The Company is seeking Board approval of each of the following:
   a. recovery of the 2011 revenue requirement from all elements of the Company's rates;
   b. the proposed rates for each customer class; and
   c. the Rate Handbook filed under Exhibit B, Tab 3, Schedule 2.

3. The Rate Handbook filed under Exhibit B, Tab 3, Schedule 2 reflects the proposed changes to the rates and Direct Purchase Administration Charge ("DPAC"). Except for the proposed rate changes and DPAC, all other components of the Rate Handbook filed under this exhibit remain as approved in EB-2010-0258 (October 1, 2010 QRAM).

Components of the 2011 Revenues

4. The derivation of the Company's 2011 revenues reflecting the Revenue Cap per Customer Incentive Regulation Model is presented at Exhibit B, Tab 1, Schedule 2, page 1. Row 26 of that exhibit represents total proposed revenues for 2011 in the amount of $2,404.89 million.

5. As shown at rows 24, 25, and 26, the 2011 proposed revenues consist of:

2011 Distribution Revenues	$ 988.59
2011 Gas Cost to Operations	$1,416.30
2011 Total Revenues	$2,404.89

6. The 2011 distribution revenues are comprised of: a) 2011 base distribution revenue in the amount of $830.09 million (Row 18), which is determined using the Revenue Cap per Customer incentive regulation escalation formula and, b) distribution related Y-factor revenues in the amount of $158.50 million (Row 23).

7. The 2011 Gas Cost to Operations reflects pass-through of gas supply costs such as commodity, upstream transportation, contracted storage, and load balancing. The Gas Cost to Operations evidence is filed at Exhibit B, Tab 4, Schedule 2.

2011 Rate Impacts

8. The Company has designed rates to recover the proposed 2011 revenues of $2,404.89 million. Table 1 below provides a summary of the resulting average rate impacts by rate class. Rate impacts for customers taking service under bundled rates are expressed on a T-service basis. Rate impacts for customers taking service under unbundled rates are expressed on a delivery rate basis.

9. The proposed rate impacts are relative to the existing October 1, 2010 QRAM Board approved rates filed under EB-2010-0258 and reflect the recovery of the proposed 2011 revenue requirement, the proposed 2011 volumetric forecast, and the proposed 2011 Gas Cost to Operations budget.

Table 1: 2011 Proposed Average Rate Impacts

Rate Class	T-Service Rate Impact
1	-0.8%
6	-1.5%
9	-0.4%
100	-2.2%
110	-3.6%
115	-4.3%
135	-4.7%
145	-3.6%
170	-5.5%
200	-3.2%
	Delivery Rate Impact
125	0.4%
300	0.4%

10. The 2011 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. Factors contributing to lower than estimated rate impacts include degree day and volume forecasts, lower forecast inflation as well as forecast gas supply mix changes.

Rate Design Exhibits

11. Rate design exhibits are filed at Exhibit B, Tab 3, Schedules 3 to 9. The exhibits present the proposed recovery of the 2011 revenues. The schedules are organized in the following manner:

a) Schedule 3 summarizes, by rate class, and rate component, the revenues at proposed rates which are forecast to be recovered in 2011. 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-2010-0258 (October 1, 2010 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.

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-2010-0258 (October 1, 2010 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 2011 forecast of Gas Costs to Operations (at October 1, 2010 QRAM prices) in the amount of $1,416.30 million including changes to the Company’s 2011 gas supply portfolio relative to the 2010 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. In addition, as outlined in Exhibit B, Tab 4, Schedule 2, the 2011 gas supply portfolio reflects changes to upstream transportation capacity as was approved in the System Reliability Decision (EB-2010-0231). The cost consequences of these changes are not reflected in the 2011 rate adjustment but will take effect in the Company’s January 1, 2011 QRAM rates. This is consistent with the Company’s QRAM methodology which adjusts rates in each quarter of a fiscal year to reflect changes in commodity and upstream transportation costs.

14. The Company's existing October 1, 2010 QRAM rates have a Purchased Gas Variance Account ("PGVA") reference price of $204.864 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 2011 yields a PGVA reference price of $204.190 10^3m^3, which represents a decrease from the October 2010 QRAM level.

15. The development of the gas commodity, load balancing, and transportation unit rates is guided by the assignment of the revenue requirement for each of these elements. The complete development of these unit rates is shown at Exhibit B, Tab 3, Schedule 7 and the allocation of the gas supply revenue requirement is shown at Exhibit B, Tab 3, Schedule 10, page 4. Storage and unaccounted for gas (i.e. distribution commodity) costs are recovered through the Company's delivery charges.

16. Within the Company's Revenue Cap per Customer Incentive Regulation Model, the assignment of the gas supply revenue requirement and the derivation of the gas commodity, load balancing, and transportation unit rates continue to be determined in the same manner as under the cost-of-service regime. This is facilitated by an annual forecast of Gas Costs to Operations and volumes budget. These forecasts provide a revenue requirement for each of the gas supply elements and enable an update to the allocators.

Rate Design: Distribution Revenues

17. The distribution revenues include a base 2011 distribution revenue requirement of $830.09 million, which is derived using the proposed Revenue Cap per Customer incentive regulation escalation formula, and distribution revenue requirement of $158.50 million for the Y-factors.

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 2011 forecast to assign the test year distribution revenue requirement to the customer classes. By updating forecasts and allocators annually, the assignment of revenue requirement by rate class, and consequently rate impacts, remain responsive to factors such as customer growth, volumes gain or loss and customer migration between various rates and service offerings. The Y-factor 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.

<u>Rate Design: 2011 Proposed Rates</u>

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 2011 revenue requirement (Exhibit B, Tab 3, Schedule 10, pp. 1 to 9) as a guide to establish the proposed rates.

21. The Company has designed the proposed 2011 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 3, Schedule 10, pages 1 and 2.

<u>Other</u>

<u>System Gas and DPAC</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. The DPAC has been updated to reflect the level of incremental cost for direct purchase management as well as 2011 projections on the number of pools and accounts. The derivation of the new DPAC is shown in the Appendix to this schedule. The DPAC can also be found in the Rate Handbook under Rider A and Rider B.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

Appendix A

Derivation of Proposed Direct Purchase Administration Charge (DPAC):

2011 Incremental Cost to support Direct Purchase option		$2,869,931
Proposed Monthly Fixed Charge	**$75.00**	
2011 Projected number of pools	1,459	
Cost Recovery through Fixed Charge		$1,313,100
2011 Projected number of accounts	535,305	
Proposed Monthly Account Charge	**$0.24**	
Cost Recovery through Account Charge		$1,556,831
Total Recovery		$2,869,931

Notes:

(1) The Monthly Fixed Charge is retained at $75 per pool.

(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

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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 (17^{th}) day following the date the bill is due.

SECTION G - TERM OF ARRANGEMENT

When gas service is provided and there is no written agreement in effect relating to the provision of such service, the term for which such service is to continue shall be one year. The term shall automatically be extended for a further year immediately following the expiry of any initial one year term or one year extension unless reasonable notice to terminate service is given to the Company, in a manner acceptable to the Company, prior to the expiry of the term. An Applicant receiving such service who temporarily discontinues service in the initial one year term or any one year extension and does not pay all the minimum bills for the period of such temporary discontinuance of service shall, upon the continuance of service, be liable to pay an amount equal to the unpaid minimum bills for such period. When a written agreement is in effect relating to the provision of gas service, the term for which such service is to continue shall be as provided for in the agreement.

SECTION H - RESALE PROHIBITION

Gas taken at a Terminal Location shall not be resold other than in accordance with all applicable laws and regulations and orders of any governmental authority or OEB having jurisdiction.

SECTION I - MEASUREMENT

The Company will install, operate and maintain at a Terminal Location such measurement equipment of suitable capacity and design as is required to measure the volume of gas delivered. Any special conditions for measurement are contained in the General Terms and Conditions which form part of each Large Volume Distribution Contract.

SECTION J - RATES IN CONTRACTS

Notwithstanding any rates for service specified in any Service Contract, the rates and charges provided for in an applicable Rate Schedule shall apply for service rendered on and after the effective date stated in such Rate Schedule until such Rate Schedule ceases to be applicable.

SECTION K - ADVICE RE: CURTAILMENT

The Company, if requested, will advise Applicants taking interruptible service of its estimate of service curtailment for the forthcoming winter. Such estimate will be provided as guidance to the Applicant in arranging for alternate fuel supply requirements. Abnormal weather and/or other unforeseen events may cause greater or lesser curtailment of service than expected.

SECTION L - DAILY DELIVERED VOLUMES

For purposes including that of calculating daily overrun gas volumes, the Company will recognize as having been delivered to it on a given day the sum of:

a) the volume of gas delivered under Intra-Alberta transportation arrangements, if any, plus;

b) the volume of gas delivered under FT transportation arrangements, if any, plus;

SECTION M - AUTHORIZED OVERRUN GAS

If an Applicant requests permission to exceed the Authorized Volume for a day, and such authorization is granted, such gas shall constitute Authorized Overrun Gas. Such gas shall either be sold by the Company to the Applicant pursuant to the provisions of Rate 320 applicable on such day, or, at the Company's sole discretion, under the Rate Schedule the customer is purchasing prior to such request. If the Applicant is supplying their own gas requirements and if the Applicant request and at the Company's sole discretion, such Overrun Gas will be debited to the Applicant's Banked gas Account.

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

If an Applicant for Transportation Service pursuant to the General Service Rates on any day delivers to the Company a Daily Delivered Volume which is less than the Mean Daily Volume, the volume of gas by which the Mean Daily Volume applicable to such day exceeds the Daily Delivered Volume delivered by the Applicant to the Company on such day shall constitute Unauthorized Supply Overrun Gas and shall be deemed to have been taken and purchased on such day. The rate applicable to such volume shall be 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and the EDA delivery areas respectively.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under the Large Volume Distribution Contract Rates is:

(a) the volume of gas by which the Daily Gas Quantity under the Service Contract on such day exceeds the Authorized Volume for such day, if any

plus

(b) if the day is in the months of December to March inclusive for an Applicant taking service on Rate 135 under Option a) or if the day is in the month of December under Option b), or if the day is a day on or in respect of which the Applicant has been requested in accordance with the Service Contract to curtail or discontinue the use of gas and the Service Contract is in whole or in part for interruptible Transportation Service, the volume of gas, if any, by which

(i) the Mean Daily Volume set out in the Service Contract and is applicable to such day exceeds

(ii) the Daily Delivered Volume delivered by the Applicant to the Company on such day, which excess volume of gas shall be deemed to have been taken and purchased by the Applicant on such day.

The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

An Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate must provide two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean Daily Volume for a specified time period. Failure to provide proper notice will result in Unauthorized Supply Overrun Gas calculated as the difference between Daily Delivered Volume and the Mean Daily Volume.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under Rate 125 or Rate 300 shall be determined from the provisions of the applicable Rate Schedule. The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

SECTION O – COMPANY RESPONSIBILTY AND LIABILITY

This Section O applies only to gas distribution service under Rates 1, 6 and 9, and does not replace or supercede the terms in any applicable Service Contract.
The Company shall make reasonable efforts to maintain, but does not guarantee, continuity of gas service to its customers. The Company may, in its sole discretion, terminate or interrupt gas service to customers;

to maintain safety and reliability on, or to facilitate construction, installation, maintenance, repair, replacement or inspection of the Company's facilities; or

for any reason related to dangerous or hazardous circumstances, emergencies or Force Majeure.

The Company shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind, whether direct, indirect, special or consequential in nature, (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising from or connected with any failure, defect, fluctuation or interruption in the provision of gas service by the Company to its customers.

PART IV

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

Any Applicant, at the time of applying for service, may elect, in and for the term of any Service Contract, to deliver its own natural gas requirements to the Company and the Company shall deliver gas to a Terminal Location as required by the Applicant, subject to the terms and conditions contained in the applicable Rate Schedule and in the Service Contract. For Buy/Sell Arrangements and Bundled T-Service the deliveries by the Applicant to the Company shall be at the Applicant's estimated mean daily rate of consumption.

Backstopping of an Applicant's natural gas supply for Transportation Service arrangements will be available pursuant to Rate 320 subject to the Company's ability to do so using reasonable commercial efforts. Gas Purchase Agreements in respect to Buy/Sell Arrangements shall specify terms and conditions available to the Company to alleviate certain consequences of the Applicant's failure to deliver the required volume of gas.

The following Terms and Conditions shall apply to, and only to, Transportation Service and/or Gas Purchase Agreements.

SECTION A - NOMINATIONS

An Applicant delivering gas to the Company pursuant to a contract is responsible for advising the Company, by means of a contractually specified Nomination procedure, of the daily volume of gas to be delivered to the Company by or on behalf of the Applicant.

An initial daily volume must be Nominated by a contractually specified time before the first day on which gas is to be delivered to the Company. Any Nomination, once accepted by the Company, shall be considered as a standing nomination applicable to each subsequent day in a contract term unless specifically varied by written notice to the Company.

A contract may specify certain contractual provisions that are applicable in the event that an Applicant either fails to advise of a revised daily nomination or fails to deliver the daily volume so nominated.

A Nominated Volume in excess of the Applicant's Maximum Daily Volume as specified in the Service Contract will not be accepted except as specifically provided for in any contract.

SECTION B - OBLIGATION TO DELIVER

During any period of curtailment or discontinuance of Bundled interruptible Transportation Service as ordered by the Company, any Applicant supplying its own gas requirements must, on such day, deliver to the Company the Mean Daily Volume of gas specified in any Service Contract.

Each Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate is obligated to deliver the Mean Daily Volume of gas as specified in any Service Contract, unless the Applicant provides two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean daily Volume for a specified time period.

An Applicant taking service on Rate 135 under Option a) must deliver to the Company the Mean Daily Volume of gas specified in the Service Contract in the months of December to March, inclusive.

An Applicant taking service on Rate 135 under Option b) must deliver to the Company the Modified Mean Daily Volume of gas specified in the Service Contract in the month of December.

Applicants taking service on General Service rates pursuant to a Direct Purchase Agreement must, on each day in the term of such agreement, deliver to the Company the Mean Daily Volume of gas specified in such agreement.

SECTION C - DIVERSION RIGHTS

Subject to compliance with the Terms and Conditions of all Required Orders, an Applicant who has entered into a Transportation Service Agreement or Agreements which provide(s) for deliveries to the Company for more than one Terminal Location shall have the right, on such terms and only on such terms as are specified in the applicable Transportation Service Agreement, to divert deliveries from one or more contractually specified Terminal Locations to other contractually specified Terminal Locations.

SECTION D - BANKED GAS ACCOUNT (BGA)

For T-Service Applicants, the Company shall keep a record ("Banked Gas Account") of the volume of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of the volume of gas taken by the Applicant at the Terminal Location (debits). (Any volume of gas sold by the Company to the Applicant in respect to the Terminal Location shall not be debited to the Banked Gas Account). The Company shall periodically report to the Applicant the net balance in the Applicant's Banked Gas Account.

SECTION E - DISPOSITION OF BANKED GAS ACCOUNT (BGA) BALANCES

A. The following Terms and Conditions shall apply to Bundled T-Service:

(a) At the end of each contract year, disposition of any net debit balance in the Banked Gas Account (BGA) shall be made as follows:

The Applicant, by written notice to the Company within thirty (30) days of the end of the contract year, may elect to return to the Company, in kind, during the one hundred and eighty (180) days following the end of the contract year, that portion of any debit balance in the Banked Gas Account as at the end of the contract year not exceeding a volume of twenty times the Applicant's Mean Daily Volume by the Applicant delivering to the Company on days agreed upon by the Company and the Applicant a volume of gas greater than the Mean Daily Volume, if any, applicable to such day under a Service Contract. Any volume of gas returned to the Company as aforesaid shall not be credited to the Banked Gas Account in the subsequent contract year. Any debit balance in the Banked Gas Account as at the end of the contract year which is not both elected to be returned, and actually returned, to the Company as aforesaid shall be deemed to have been sold to the Applicant and the Applicant shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be:

(1) for *Bundled Western T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

(2) for *Bundled Ontario T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, plus the Company's average transportation cost to its franchise area over the contract year.

(b) A credit balance in the Banked Gas Account as at the end of the contract year must be eliminated in one or more of the following manners, namely:

(i) Subject to clause (ii), if the Applicant continues to take service from the Company under a contract pursuant to which the Applicant delivers gas to the Company and the Applicant so elects (by written notice to the Company within thirty (30) days of the end of the contract year), that portion of such balance which the Applicant stipulates in such written notice and which does not exceed twenty times the Applicant's Mean Daily Volume may be carried forward as a credit to the Banked Gas Account for the next succeeding contract year. Any volume duly elected to be carried forward under this clause shall, and may only, be reduced within the period of one hundred and eighty (180) days ("Adjustment Period") immediately following the contract year, by the Applicant delivering to the Company, on days in the Adjustment Period agreed upon by the Company and the Applicant ("Adjustment Days"), a volume of gas less than the Mean Daily Volume applicable to such day under a Service Contract. Subject to the foregoing, the credit balance in the Banked Gas Account shall be deemed to be reduced on each Adjustment Day by the volume ("Daily Reduction Volume") by which the Mean Daily Volume applicable to such day exceeds the greater of the volume of gas delivered by the Applicant on such day and the Nominated Volume for such day which was accepted by the Company.

(ii) Any portion of a credit balance in the Banked Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to the Company within thirty (30) days of the end of the contract year) to sell under this clause, shall be deemed to have been tendered for sale to the Company and the Company shall purchase such portion at:

(1) for *Bundled Western T*-Service, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the Company's average transportation cost to its franchise area over the contract year.

(2) for *Bundled Ontario T-Service*, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

Any volume of gas deemed to have been so tendered for sale shall be deemed to have been eliminated from the credit balance of the Banked Gas Account.

During the Adjustment Period the Company shall use reasonable efforts to accept the Applicant's reduced gas deliveries. Any credit balance in the Banked Gas Account not eliminated as aforesaid in the Adjustment Period shall be forfeited to, and be the property of, the Company, and such volume of gas shall be debited to the Banked Gas Account as at the end of the Adjustment Period.

Subject to its ability to do so, the Company will attempt to accommodate arrangements which would permit adjustments to Banked Gas Account balances at times and in a manner which are mutually agreed upon by the Applicant and the Company.

B. The following Terms and Conditions shall apply to Unbundled Service:

The Terms and Conditions for disposition of Cumulative Imbalance Account balances shall be as specified in the applicable Service Contracts.

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a residential building served through one meter and containing no more than six dwelling units ("Terminal Location").

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$19.00**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**8.0068 ¢/m³**
For the next 55 m³ per month	**7.5364 ¢/m³**
For the next 85 m³ per month	**7.1678 ¢/m³**
For all over 170 m³ per month	**6.8934 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.4565 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

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		**$65.00**
Delivery Charge per cubic metre		
For the first	500 m³ per month	**7.6047 ¢/m³**
For the next	1050 m³ per month	**5.9663 ¢/m³**
For the next	4500 m³ per month	**4.8193 ¢/m³**
For the next	7000 m³ per month	**4.0821 ¢/m³**
For the next	15250 m³ per month	**3.7546 ¢/m³**
For all over	28300 m³ per month	**3.6725 ¢/m³**
Transportation Charge per cubic metre		**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)		**15.5210 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

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	**$235.89**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**10.7691 ¢/m³**
For all over 20,000 m³ per month	**10.0804 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3459 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

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	**$122.01**
Delivery Charge	
Per cubic metre of Contract Demand	**8.1900 ¢/m³**
For the first 14,000 m³ per month	**5.1296 ¢/m³**
For the next 28,000 m³ per month	**3.7706 ¢/m³**
For all over 42,000 m³ per month	**3.2116 ¢/m³**
Gas Supply Load Balancing Charge	**0.5055 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3599 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: **100**

MINIMUM BILL:

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

10.4139 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

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	**$587.37**
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	**0.5996 ¢/m³**
For all over 1,000,000 m³ per month	**0.4496 ¢/m³**
Gas Supply Load Balancing Charge	**0.1400 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3459 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

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

5.5184 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 292 times a specified maximum daily volume of not less than 1,165 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month
	January to December
Monthly Customer Charge	**$622.62**
Delivery Charge	
Per cubic metre of Contract Demand	**24.3600 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.3285 ¢/m³**
For all over 1,000,000 m³ per month	**0.2285 ¢/m³**
Gas Supply Load Balancing Charge	**0.0472 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3459 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

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

5.1545 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

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	**9.0768 ¢/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 = 0.7255 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 0.8706 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 1.066 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, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

RATE NUMBER: **135**	**SEASONAL FIRM 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 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	**$115.08**	**$115.08**
Delivery Charge		
For the first 14,000 m³ per month	**6.7616 ¢/m³**	**2.0616 ¢/m³**
For the next 28,000 m³ per month	**5.5616 ¢/m³**	**1.3616 ¢/m³**
For all over 42,000 m³ per month	**5.1616 ¢/m³**	**1.1616 ¢/m³**
Gas Supply Load Balancing Charge	**0.0000 ¢/m³**	**0.0000 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.4267 ¢/m³**	**15.4267 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

The applicant has the option of delivering either Option a) a Mean Daily Volume ("MDV") based on 12 months, or Option b) a Modified Mean Daily Volume ("MMDV") based on nine months of deliveries. Authorized Volumes for the months of January, February and March would be zero under option b).

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Failure to deliver a volume of gas equal to the Mean Daily Volume under Option a) set out in the Service Contract during the months of December to March inclusive may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

Failure to deliver a volume of gas equal to the Modified Mean Daily Volume under Option b) set out in the Service Contract during the month of December may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

RATE NUMBER: **135**

SEASONAL CREDIT:

Rate per cubic metre of Mean Daily Volume from December to March	**$**	**0.77 /m³**
Rate per cubic metre of Modified Mean Daily Volume for December	**$**	**0.77 */m³***

SEASONAL OVERRUN CHARGE:

During the months of December through March inclusively, any volume of gas taken in a single month in excess of five percent of the annual contract volume (Seasonal Overrun Monthly Volume) will be subject to Seasonal Overrun Charges in place of both the Delivery and Gas Supply Load Balancing Charges. The Seasonal Overrun Charge applicable for the months of December and March shall be calculated as 2.0 times the sum of the Gas Supply Load Balancing Charge, Transportation Charge and the maximum Delivery Charge. The Seasonal Overrun Charge applicable for the months of January and February shall be calculated as 5.0 times the sum of the Load Balancing Charge, Transportation Charge and the maximum Delivery Charge.

Seasonal Overrun Charges:

December and March	**23.1666 ¢/m³**
January and February	**57.9165 ¢/m³**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **8.4070 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service as ordered by the Company exercising its sole discretion. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source. Any Applicant for service under this rate schedule must agree to transport a minimum annual volume of 340,000 cubic metres.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 16 hours prior to the time at which such curtailment or discontinuance is to commence. An Applicant may, by contract, agree to accept a shorter notice period.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$123.34**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.8453 ¢/m³**
For the next 28,000 m³ per month	**1.4863 ¢/m³**
For all over 42,000 m³ per month	**0.9273 ¢/m³**
Gas Supply Load Balancing Charge	**0.3785 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.5112 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 16 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 0.50 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**8.0026 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas of not less than 30,000 cubic metres and a minimum annual volume of 5,000,000 cubic metres to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service when required by the Company. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source. The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$279.31**
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	**0.5242 ¢/m³**
For all over 1,000,000 m³ per month	**0.3242 ¢/m³**
Gas Supply Load Balancing Charge	**0.2105 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3459 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

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

5.5135 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

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	**1.1289 ¢/m³**
Gas Supply Load Balancing Charge	**0.5403 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3459 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**15.3224 ¢/m³**

The rates quoted above shall be subject to the Gas Inventory Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable to volumes of natural gas purchased from the Company. The volumes purchased shall be the volumes delivered at the Point of Delivery less any volumes, which the Company does not own and are received at the Point of Acceptance for delivery to the Applicant at the Point of Delivery.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**1.10 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

The third instance of such failure in any contract year may result in the Applicant orfeiting the right to be served under this Rate Schedule. In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**6.4480 ¢/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, 2011 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

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	**24.9189 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3581 ¢/m³**
Maximum Delivery Charge	**0.9831 ¢/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 0.7255 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 0.8706 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 0.7009 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, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

APPLICABILITY:

This rate is available to any customer taking service under Distribution Rates 125 and 300. It requires a Service Contract that identifies the required storage space and deliverability. In addition, the customer shall maintain a positive balance of gas in storage at all times or forfeit the use of Storage Services for Load Balancing and No-Notice Storage Service.

A daily nomination for storage injection and withdrawal except for No-Notice Storage Service, hereunder, which is used automatically for daily Load Balancing, shall also be required.

The maximum hourly injections / withdrawals shall equal $1/24^{th}$ of the daily Storage Demand. No-Notice Storage Service is available up to the maximum daily withdrawal rights less the nominated withdrawal or the maximum daily injection rights less the nominated injections.

Storage space shall be based on either of two storage allocation methodologies: (customer's average winter demand - customer's average annual demand) x 151, or [(17 x customers's maximum hourly demand) / 0.1] x 0.57. Customers have the option to select from these two storage space allocation methods the one that best suits their requirements.

Maximum deliverability shall be 1.2% of contracted storage space. The customer may inject and withdraw gas based on the quantity of gas in storage and the limitations specified in the Service Contract. Both injection and withdrawal shall be subject to applicable storage ratchets as determined by the Company and posted from time to time.

CHARACTER OF SERVICE:

Service shall be firm when used in conjunction with firm distribution service. Service is interruptible when used in conjunction with interruptible distribution service. All service is subject to contract terms and force majeure.

The service is available on two bases:

(1) Service nominated daily based on the available capacity and gas in storage up to the maximum contracted daily deliverability; and

(2) No-Notice Storage Service for daily Load Balancing consistent with the maximum hourly deliverability.

RATE:

The following rates and charges shall apply in respect to all gas received by the Company from and delivered by the Company to storage on behalf of the Applicant.

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0585 ¢/m³**
Monthly Storage Deliverability Demand Charge	**15.2792 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.3500 ¢/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, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

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 1/24th 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	**0.0585 ¢/m³**
Monthly Storage Deliverability Demand Charge	**5.2711 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.1074 ¢/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, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

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	**20.7023 ¢/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, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

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	**0.1870**	**0.2253**
Maximum Daily Withdrawal Volume	**16.9047**	**20.4355**
Commodity Charge	**0.9875**	**0.3369**

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	**2.4682**	**0.5558**
Unauthorized	**-**	**223.1420**
Pool Storage		
Authorized	**2.9738**	**0.6719**
Unauthorized	**-**	**269.7482**

(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, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

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	**0.4123**	**0.4123**	**-**
Maximum	**2.0615**	**2.0615**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**37.3402**	**29.8722**	**-**
Maximum	**186.7010**	**149.3608**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**1.3244**	**1.3244**	**0.6841**
Maximum	**6.6220**	**6.6220**	**38.6149**

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

TRANSACTING IN ENERGY:

The conversion factor is 37.74MJ/m3, which corresponds to Union Gas' System Wide Average Heating Value, as per the Board's RP-1999-0017 Decision with Reasons.

MINIMUM BILL:

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

RATE NUMBER: **330**

OVERRUN RATES:

The units rates stated below will apply to overrun volumes. The provision of Authorized Overrun service will be at the Company's sole discretion.

	Full Cycle		Short Cycle
	Firm $/10³m³	**Interruptible** $/10³m³	$/10³m³
Authorized Overrun Annual Turnover Volume Negotiable, not to exceed:	**38.6149**	**38.6149**	**38.6149**
Authorized Overrun Daily Injection/Withdrawal Negotiable, not to exceed:	**38.6149**	**38.6149**	**38.6149**
Unauthorized Overrun Annual Turnover Volume Excess Storage Balance			
September 1 - November 30	**386.1490**	**386.1490**	**386.1490**
December 1 - October 31	**38.6149**	**38.6149**	**38.6149**
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, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into an agreement with the Company pursuant to the Rate 331 Tariff ("Tariff"), as approved by the Board from time to time, for transportation service on the Company's pipelines extending from Tecumseh to Dawn ("Tecumseh Pipeline"), as such locations are defined in the Tariff. The Company will receive gas at Tecumseh and deliver the gas at Dawn.

Parts I to IV do not apply to Rate 331 service. Capitalized terms used in this Rate Schedule shall have the meanings ascribed to those terms in the Tariff.

CHARACTER OF SERVICE:

Transportation service under this Rate Schedule may be available on a firm basis ("FT Service") or an interruptible basis ("IT Service"), subject to the terms and conditions of service set out in the Tariff and the applicable rates set out below.

RATE:

The following rates, effective January 1, 2011, shall apply in respect of FT and IT Service under this Rate Schedule:

	Demand Rate $\$/10^3m^3$	Commodity Rate $\$/10^3m^3$
FT Service	**5.2700**	**-**
IT Service	**-**	**0.2080**

Calculation of Charges

FT Service: The monthly demand charge shall be the sum of the products obtained by multiplying the applicable Maximum Daily Volume by the above demand rate for each Day of the Month.

IT Service: The monthly commodity charge shall be the product obtained by multiplying the applicable Delivery Volume for the Month by the above commodity rate.

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

TERMS AND CONDITIONS OF SERVICE:

The terms and conditions of FT and IT Service are set out in the Tariff. The current form of the Tariff was approved by the Board in Board Order EB-2010-0186, effective July 1, 2010, posted and available on the Company's website. In accordance with Section 1.6.2 of the Board's Storage and Transportation Access Rule, the Tariff does not apply to any transportation service agreements executed prior to June 16, 2010.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

Applicants located off the piping networks noted below or off piping systems supplied from these networks may be curtailed to maintain distribution system integrity.

The Town of Collingwood
The Town of Midland

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Transportation Agreement with the Company under any rate other than Rates 125 and 300.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00 per month
Account Charge	$0.24 per month per account

AVERAGE COST OF TRANSPORTATION:

The average cost of transportation effective October 1, 2010:

Point of Acceptance	Firm Transportation (FT)
CDA, EDA	4.8217 ¢/m³

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

APPLICABILITY:

To Ontario T-Service and Western T-Service customers who have been or will be assigned TCPL capacity by the Company.

TERMS AND CONDITIONS OF SERVICE:

1. The Company will accommodate TCPL FT capacity turnback requests from customers, but only if it can do so in accordance with the following considerations:
   i. The FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to the TCPL FT capacity;
   ii. The amount of turnback capacity that Enbridge otherwise may accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs resulting from the loss of STS capacity arising from any turnback request; and
   iii. Enbridge must act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.
2. Requests for TCPL FT turnback must be made in writing to the attention of Enbridge's Direct Purchase group.
3. All TCPL FT capacity turnback requests will be treated on an equitable basis.
4. The percentage turnback of TCPL FT capacity will be applied at the Direct Purchase Agreement level.

5. Written notice to turnback capacity must be received by the Company the earlier of:

   (a) Sixty days prior to the expiry date of the current contract.

   or

   (b) A minimum of one week prior to the deadline specified in TransCanada tariff for FT contract extension.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

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	$0.24	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, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

The following adjustment is applicable to all gas sold or delivered during the period of January 1, 2011 to September 30, 2011.

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

Rate Class		Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 1	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 6	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 9	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 100	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 110	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 115	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 135	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000

Rate Class		Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 145	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 170	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 200	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000

RIDER: E	REVENUE ADJUSTMENT RIDER

Bundled Services

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

Unbundled Services

Rate Class	Distribution Service (¢/m³)
Rate 125	0.0000
Rate 300	0.0000

ATMOSPHERIC PRESSURE FACTORS

The following elevation factors shall be applicable to metered volumes measured by a meter that does not correct for atmospheric pressure.

Zone	Elevation Factor
1	0.9644
2	0.9652
3	0.9669
4	0.9678
5	0.9686
6	0.9703
7	0.9728
8	0.9745
9	0.9762
10	0.9771
11	0.9839
12	0.9847
13	0.9856
14	0.9864
15	0.9873
16	0.9881
17	0.9890
18	0.9898
19	0.9907
20	0.9915
21	0.9932
22	0.9941
23	0.9949
24	0.9958
25	0.9960
26	0.9966
27	0.9975
28	0.9981
29	0.9983
30	0.9992
31	0.9997
32	1.0000
33	1.0017
34	1.0025
35	1.0034
36	1.0051
37	1.0059
38	1.0170

	Rate (excluding GST)
New Account Or Activation	
New Account Charge Turning on of gas, activating appliances, obtaining billing data and establishing an opening meter reading for new customers in premises where gas has been previously supplied	$25.00
Appliance Activation Charge - Commercial Customers Only Commercial customers are charged an appliance activation charge on unlock and red unlock orders, except on the very first unlock and service unlock at a premise.	$70.00 minimum 1/2 hour work. Total Amount depends on time required
Meter Unlock Charge - Seasonal or Pool Heater Seasonal for all other revenue classes, or Pool Heater for residential only	$70.00
Statement of Account	
Lawyer Letter Handling Charge Provide the customer's lawyer with gas bill information.	$15.00
Statement of Account Charge (for one year history)	$10.00
Cheques Returned Non-Negotiable Charge	$20.00
Gas Termination	
Red Lock Charge Locking meter or shutting off service by closing the street shut-off valve (when work can be performed by Field Collector)	$70.00
Removal of Meter Removing meter by Construction & Maintenance crew	$280.00
Cut Off At Main Charge Cutting service off at main by Construction & Maintenance Crew	$1,300.00
Valve Lock Charge Shutting off service by closing the street	
shut-off valve - work performed by Field Investigator	$135.00
- work performed by Construction & Maintenance	$280.00

Safety Inspection	
Inspection Charge For inspection of gas appliances; the Company provides only one inspection free of charge, upon first time introduction of gas to a premise.	$70.00
Inspection Reject Charge (safety inspection) Energy Board Inspection rejects are billed to the meter installer or homeowner.	$70.00
Meter Test	
Meter Test Charge When a customer disputes the reading on his/her meter, he/she may request to have the meter tested. This charge will apply if the test result confirms the meter is recording consumption correctly.	
Residential meters	$105.00
Non-Residential meters	Time & Material per Contractor
Street Service Alteration	
Street Service Alteration Charge For installation of service line beyond allowable guidelines (for new residential services only)	$32.00
NGV Rental	
NGV Rental Cylinder (weighted average)	$12.00
Other Customer Services (ad-hoc request)	
Labour Hourly Charge-Out Rate	$140.00
Cut Off At Main Charge - Commercial & Special Requests Cut Off At Main charges for commercial services and other residential services that involve significantly more work than the average will be custom quoted.	custom quoted
Cut Off At Main Charge - Other Customer Requests Other residential Cut Off At Main requests due to demolitions, fires, inactive services, etc. will be charged at the standard COAM rate.	$1,300.00
Meter In-Out (Residential Only)) Relocate the meter from inside to outside per customer request	$280.00
Request For Service Call Information Provide written information of the result of a service call as requested by home owners.	$30.00
Temporary Meter Removal As requested by customers.	$280.00
Damage Meter Charge	$380.00

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Delivery Agreement with the Company under any rate.

IN FRANCHISE TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, an Applicant may elect to initiate a transfer of natural gas from one of its pools to the pool of another Applicant for the purposes of reducing an imbalance between the Applicant's deliveries and consumption as recorded in its Banked Gas Account or Cumulative Imbalance Account. Elections must be made in accordance with the Company's policies and procedures related to transaction requests under the Gas Delivery Agreement.

The Company will not apply 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	$0.6622	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-2010-0146 RATES				
ITEM NO.	RATE NO.	DISTRIBUTION	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL
1.	1	721,765	184,986	33,596	518,774	1,459,122
2.	6	317,310	145,346	29,335	347,007	838,999
3.	9	90	27	0	63	180
4.	100	0	0	0	0	0
5.	110	10,484	9,610	661	9,898	30,653
6.	115	6,371	1,272	242	63	7,948
7.	125	7,291	0	0	0	7,291
8.	135	835	1,390	(422)	93	1,897
9.	145	5,210	4,439	(402)	3,465	12,712
10.	170	4,726	6,119	(5,604)	7,662	12,902
11.	200	3,737	5,965	746	18,984	29,431
12.	300	412	0	0	0	412
13.	SUB-TOTAL	1,078,231	359,154	58,152	906,008	2,401,546
14.	STORAGE	1,601	0	0	0	1,601
15.	DPAC	2,870	0	0	0	2,870
16.	TOTAL	1,082,701	359,154	58,152	906,008	2,406,016

Witnesses: J. Collier
A. Kacicnik

PROPOSED VOLUMES AND REVENUE RECOVERY BY RATE CLASS ($000)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
		DISTRIBUTION			GAS SUPPLY TRANSPORTATION			GAS SUPPLY LOAD BALANCING			GAS SUPPLY COMMODITY			TOTAL
ITEM NO.	RATE NO.	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	REVENUES
		10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	$000
1.	1	4,764,426	721,765	15.15	3,836,515	184,986	4.82	4,764,426	33,596	0.71	3,356,349	518,774	15.46	1,459,122
2.	6	4,518,434	317,310	7.02	3,014,405	145,346	4.82	4,518,434	29,335	0.65	2,235,728	347,007	15.52	838,999
3.	9	558	90	16.20	558	27	4.82	558	0	0.00	408	63	15.35	180
4.	100	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0
5.	110	471,855	10,484	2.22	199,310	9,610	4.82	471,855	661	0.14	64,501	9,898	15.35	30,653
6.	115	513,097	6,371	1.24	26,383	1,272	4.82	513,097	242	0.05	410	63	15.35	7,948
7.	125	0	7,291	0.00	0	0	0.00	0	0	0.00	0	0	0.00	7,291
8.	135	50,028	835	1.67	28,838	1,390	4.82	50,028	(422)	(0.84)	600	93	15.43	1,897
9.	145	237,331	5,210	2.20	92,073	4,439	4.82	237,331	(402)	(0.17)	22,339	3,465	15.51	12,712
10.	170	563,271	4,726	0.84	126,895	6,119	4.82	563,271	(5,604)	(0.99)	49,927	7,662	15.35	12,902
11.	200	157,393	3,737	2.37	123,704	5,965	4.82	157,393	746	0.47	123,704	18,984	15.35	29,431
12.	300	30,000	412	0.00	0	0	0.00	0	0	0.00	0	0	0.00	412
13	SUB-TOTAL	11,306,393	1,078,231	9.54	7,448,681	359,154	4.8217	11,276,393	58,152	0.52	5,853,968	906,008	15.48	2,401,546
14.	STORAGE	N/A	1,601	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,601
15.	DPAC	N/A	2,870	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	2,870
16.	TOTAL	11,306,393	1,082,701	9.54	7,448,681	359,154	4.82	11,276,393	58,152	0.52	5,853,968	906,008	15.48	2,406,016

Witnesses: J. Collier, A. Kacicnik

REVENUE - PROPOSED METHODOLOGY BY RATE CLASS

	Col. 1	Col. 2	Col. 3	Col. 4
		REVENUE -EB-2010-0146 RATES		
Item No.	Rate No.	Proposed Revenue ($000)	Unbilled Revenue ($000)	Total ($000)
1.	1	1,459,122	(602)	1,458,520
2.	6	838,999	(570)	838,428
3.	9	180	0	180
4.	100	0	0	0
5.	110	30,653	(19)	30,634
6.	115	7,948	4	7,952
7.	125	7,291	0	7,291
8.	135	1,897	(9)	1,888
9.	145	12,712	75	12,787
10.	170	12,902	(2)	12,900
11.	200	29,431	0	29,431
12.	300	412	0	412
13.	SUB-TOTAL	2,401,546	(1,123)	2,400,422
14.	STORAGE	1,601	0	1,601
15.	DPAC	2,870	0	2,870
16.	TOTAL	2,406,016	(1,123)	2,404,893

Witnesses: J. Collier
A. Kacicnik

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

Item No.	Rate No.	Col. 1	Col. 2 Rate Block m³		Col. 3 EB-2010-0258 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2010-0146 cents *
	RATE 1						
1.01		Customer Charge			$18.00	$1.00	$19.00
1.02		Delivery Charge	first	30	7.7315	(0.4299)	7.3016
1.03			next	55	7.2334	(0.4022)	6.8312
1.04			next	85	6.8431	(0.3805)	6.4626
1.05			over	170	6.5525	(0.3644)	6.1882
1.06		Gas Supply Load Balancing			0.6655	0.0397	0.7052
1.07		Gas Supply Transportation			5.1042	(0.2825)	4.8217
1.08		Gas Supply Commodity - System			15.4224	0.0341	15.4565
1.09		Gas Supply Commodity - Buy/Sell			15.4000	0.0329	15.4329
	RATE 6						
2.01		Customer Charge			$60.00	$5.00	$65.00
2.02		Delivery Charge	First 500		7.2015	(0.2459)	6.9555
2.03			Next 1050		5.5052	(0.1880)	5.3171
2.04			Next 4500		4.3176	(0.1475)	4.1701
2.05			Next 7000		3.5543	(0.1214)	3.4329
2.06			Next 15250		3.2152	(0.1098)	3.1054
2.07			Over 28300		3.1302	(0.1069)	3.0233
2.08		Gas Supply Load Balancing			0.6265	0.0227	0.6492
2.09		Gas Supply Transportation			5.1042	(0.2825)	4.8217
2.10		Gas Supply Commodity - System			15.5079	0.0131	15.5210
2.11		Gas Supply Commodity - Buy/Sell			15.4855	0.0120	15.4975
	RATE 9						
3.01		Customer Charge			$233.12	$2.77	$235.89
3.02		Delivery Charge	first	20000	10.6384	0.1265	10.7649
3.03			over	20000	9.9578	0.1184	10.0762
3.04		Gas Supply Load Balancing			0.0033	0.0009	0.0042
3.05		Gas Supply Transportation			5.1042	(0.2825)	4.8217
3.06		Gas Supply Commodity - System			15.2837	0.0622	15.3459
3.07		Gas Supply Commodity - Buy/Sell			15.2613	0.0611	15.3224
	RATE 100						
4.01		Customer Charge			$121.52	$0.49	$122.01
4.02		Demand Charge (Cents/Month/m³)			8.1900	0.0000	8.1900
4.03		Delivery Charge	first	14,000	5.1166	0.0130	5.1296
4.04			next	28,000	3.7576	0.0130	3.7706
4.05			over	42,000	3.1986	0.0130	3.2116
4.06		Gas Supply Load Balancing			0.4808	0.0227	0.5055
4.07		Gas Supply Transportation			5.1042	(0.2825)	4.8217
4.08		Gas Supply Commodity - System			15.3469	0.0131	15.3599
		Gas Supply Commodity - Buy/Sell			15.3283	0.0120	15.3412
	RATE 110						
5.01		Customer Charge			$585.00	$2.37	$587.37
5.02		Demand Charge (Cents/Month/m³)			22.9100	0.0000	22.9100
5.03		Delivery Charge	first	1,000,000	0.5918	0.0078	0.5996
5.04			over	1,000,000	0.4418	0.0078	0.4496
5.05		Load Balancing Commodity			0.1332	0.0068	0.1400
5.06		Gas Supply Transportation			5.1042	(0.2825)	4.8217
5.07		Gas Supply Commodity - System			15.2837	0.0622	15.3459
5.08		Gas Supply Commodity - Buy/Sell			15.2613	0.0611	15.3224

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
Item No.	Rate No.		Rate Block m³	EB-2010-0258 cents *	Rate Change cents *	EB-2010-0146 cents *
	RATE 115					
1.01		Customer Charge		$620.86	$1.76	$622.62
1.02		Demand Charge (Cents/Month/m³)		24.3600	0.0000	24.3600
1.03		Delivery Charge	first 1,000,000	0.3252	0.0033	0.3285
1.04			over 1,000,000	0.2252	0.0033	0.2285
1.05		Load Balancing Commodity		0.0448	0.0024	0.0472
1.06		Gas Supply Transportation		5.1042	(0.2825)	4.8217
1.07		Gas Supply Commodity - System		15.2837	0.0622	15.3459
1.08		Gas Supply Commodity - Buy/Sell		15.2613	0.0611	15.3224
	RATE 125					
2.01		Customer Charge		$ 500.00	$0.00	$ 500.00
2.02		Delivery Charge (Cents/Month/m³ of Contract Dmnd)		9.0378	0.0390	9.0768
	RATE 135	DEC - MAR				
3.00		Customer Charge		$114.82	$0.26	$115.08
3.01		Delivery Charge	first 14,000	6.7580	0.0036	6.7616
3.02			next 28,000	5.5580	0.0036	5.5616
3.03			over 42,000	5.1580	0.0036	5.1616
3.04		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.05		Gas Supply Transportation		5.1042	(0.2825)	4.8217
3.06		Gas Supply Commodity - System		15.3462	0.0805	15.4267
3.07		Gas Supply Commodity - Buy/Sell		15.3238	0.0794	15.4032
	RATE 135	APR - NOV				
3.08		Customer Charge		$114.82	$0.26	$115.08
3.09		Delivery Charge	first 14,000	2.0580	0.0036	2.0616
3.10			next 28,000	1.3580	0.0036	1.3616
3.11			over 42,000	1.1580	0.0036	1.1616
3.12		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.13		Gas Supply Transportation		5.1042	(0.2825)	4.8217
3.14		Gas Supply Commodity - System		15.3462	0.0805	15.4267
3.15		Gas Supply Commodity - Buy/Sell		15.3238	0.0794	15.4032
	RATE 145					
4.00		Customer Charge		$122.73	$0.61	$123.34
4.01		Demand Charge (Cents/Month/m³)		8.2300	0.000	8.2300
4.02		Delivery Charge	first 14,000	2.8352	0.0101	2.8453
4.03			next 28,000	1.4762	0.0101	1.4863
4.04			over 42,000	0.9172	0.0101	0.9273
4.05		Gas Supply Load Balancing		0.3611	0.0174	0.3785
4.06		Gas Supply Transportation		5.1042	(0.2825)	4.8217
4.07		Gas Supply Commodity - System		15.4626	0.0486	15.5112
4.08		Gas Supply Commodity - Buy/Sell		15.4402	0.0474	15.4876
	RATE 170					
5.00		Customer Charge		$278.27	$1.04	$279.31
5.01		Demand Charge (Cents/Month/m³)		4.0900	0.0000	4.0900
5.02		Delivery Charge	first 1,000,000	0.5211	0.0030	0.5242
5.03			over 1,000,000	0.3211	0.0030	0.3242
5.04		Gas Supply Load Balancing		0.2024	0.0081	0.2105
5.05		Gas Supply Transportation		5.1042	(0.2825)	4.8217
5.06		Gas Supply Commodity - System		15.2837	0.0622	15.3459
5.07		Gas Supply Commodity - Buy/Sell		15.2613	0.0611	15.3224

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2010-0258 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2010-0146 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		1.1218	0.0071	1.1289
1.03		Gas Supply Load Balancing		0.5180	0.0223	0.5403
1.04		Gas Supply Transportation		5.1042	(0.2825)	4.8217
1.05		Gas Supply Commodity - System		15.2837	0.0622	15.3459
1.06		Gas Supply Commodity - Buy/Sell		15.2613	0.0611	15.3224
	RATE 300	FIRM SERVICE				
2.00		Monthly Customer Charge		$500.00	$0.00	$500.00
2.01		Demand Charge (Cents/Month/m³)		24.8117	0.1072	24.9189
		INTERRUPTIBLE SERVICE				
2.02		Minimum Delivery Charge (Cents/Month/m³)		0.3566	0.0015	0.3581
2.03		Maximum Delivery Charge (Cents/Month/m³)		0.9789	0.0042	0.9831
	RATE 315					
		Monthly Customer Charge		$150.00	$0.00	$150.00
3.00		Space Demand Chg (Cents/Month/m³)		0.0539	0.0046	0.0585
3.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		14.7300	0.5492	15.2792
3.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.3264	0.0236	0.3500
	RATE 320					
4.00		Backstop	All Gas Sold	20.9115	(0.2092)	20.7023
	RATE 316					
		Monthly Customer Charge		$150.00	$0.00	$150.00
5.00		Space Demand Chg (Cents/Month/m³)		0.0539	0.0045	0.0585
5.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		5.0696	0.2015	5.2711
5.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.1066	0.0009	0.1074

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2010-0258 cents *	Col. 4 Change cents *	Col. 5 EB-2010-0146 cents *
	RATE 325					
		Transmission & Compression				
1.00		Demand Charge - ATV ($/Month/10³ m³)		0.1865	0.0005	0.1870
1.01		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		16.8575	0.0472	16.9047
1.02		Commodity Charge		0.9810	0.0065	0.9875
		Storage				
1.03		Demand Charge - ATV ($/Month/10*3 m³)		0.2212	0.0041	0.2253
1.04		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		20.0617	0.3738	20.4355
1.05		Commodity Charge		0.3370	(0.0001)	0.3369
	RATE 330	Storage Service - Firm				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.00		Minimum		0.4077	0.0046	0.4123
2.01		Maximum		2.0385	0.0230	2.0615
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.02		Minimum		36.9192	0.4210	37.3402
2.03		Maximum		184.5960	2.1050	186.7010
		Commodity Charge				
2.04		Minimum		1.3180	0.0064	1.3244
2.05		Maximum		6.5900	$0.0320	6.6220
		Storage Service - Interruptible				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.06		Minimum		0.4077	0.0046	0.4123
2.07		Maximum		2.0385	0.0230	2.0615
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.08		Minimum		29.5354	0.3368	29.8722
2.09		Maximum		147.6768	$1.6840	149.3608
		Commodity Charge				
2.10		Minimum		1.3180	0.0064	1.3244
2.11		Maximum		6.5900	0.0320	6.6220
		Storage Service - Off Peak				
		Commodity Charge				
2.12		Minimum		0.6774	0.0067	0.6841
2.13		Maximum		38.2222	0.3927	38.6149
	RATE 331	Tecumseh Transmission Service				
		Firm				
		Demand Charge ($/Month/10³ m³ of				
3.00		Maximum Contracted Daily Delivery)		5.2580	0.0120	5.2700
		Interruptible				
3.01		Commodity Charge ($/10³m³ of gas delivered)		0.2070	0.0010	0.2080

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

CALCULATION OF GAS SUPPLY CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF GAS SUPPLY CHARGE												
	GAS SUPPLY COSTS ($000)												
1.1	Annual Commodity	896,014	513,726	342,203	63	-	9,873	63	92	3,419	7,642	18,934	
1.2	Bad Debt Commodity	7,663	3,711	3,915	-	-	-	-	0	37	-	-	
1.3	System Gas Fee	1,378	790	526	0	-	15	0	0	5	12	29	
1.4	Return on Rate Base - Working Cash	953	546	364	0	-	10	0	0	4	8	20	
1	Total Commodity Costs	906,008	518,774	347,008	63	-	9,898	63	93	3,465	7,662	18,984	
	VOLUMES (10^3 m^3)												
2.1	System and Buy/Sell Volumes	5,853,968	3,356,349	2,235,728	408	-	64,501	410	600	22,339	49,927	123,704	
2.2	System Volumes	5,853,968	3,356,349	2,235,728	408	-	64,501	410	600	22,339	49,927	123,704	
	GAS SUPPLY CHARGE SYSTEM (¢/m^3)												
3.1	Annual Commodity	15.3061	15.3061	15.3061	15.3061	-	15.3061	15.3061	15.3061	15.3061	15.3061	15.3061	1.1 / 2.1
3.2	Bad Debt Commodity	0.1309	0.1106	0.1751	-	-	-	-	0.0808	0.1653	-	-	1.2 / 2.1
3.3	System Gas Fee	0.0235	0.0235	0.0235	0.0235	-	0.0235	0.0235	0.0235	0.0235	0.0235	0.0235	1.3 / 2.2
3.4	Return on Rate Base - Working Cash	0.0163	0.0163	0.0163	0.0163	-	0.0163	0.0163	0.0163	0.0163	0.0163	0.0163	1.4 / 2.1
3	System Gas Supply Charge	15.4768	15.4565	15.5210	15.3459	-	15.3459	15.3459	15.4267	15.5112	15.3459	15.3459	
	GAS SUPPLY CHARGE BUY/SELL(¢/m3)												
4.1	Annual Commodity	15.3061	15.3061	15.3061	15.3061	-	15.3061	15.3061	15.3061	15.3061	15.3061	15.3061	1.1 / 2.1
4.2	Bad Debt Commodity	0.1309	0.1106	0.1751	-	-	-	-	0.0808	0.1653	-	-	1.2 / 2.1
4.3	Return on Rate Base - Working Cash	0.0163	0.0163	0.0163	0.0163	-	0.0163	0.0163	0.0163	0.0163	0.0163	0.0163	1.4 / 2.1
4	Buy/Sell Gas Supply Charge	15.4533	15.4329	15.4975	15.3224	-	15.3224	15.3224	15.4032	15.4876	15.3224	15.3224	

Witnesses: J. Collier
A. Kacicnik

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	11,981	6,546	5,224	-	-	71	24	-	-	-	117	
5.2	Seasonal	23,887	11,794	10,512	0	-	257	95	-	392	517	320	
5.3	Return on Rate Base - Gas in Inventory	30,901	15,257	13,599	0	-	333	123	-	507	669	413	
5	Total Load Balancing	66,769	33,596	29,335	0	-	661	242	-	898	1,186	850	
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,276,393	4,764,426	4,518,434	558	-	471,855	513,097	50,028	237,331	563,271	157,393	
7	**ANNUAL LOAD BALANCING CHARGE (¢/m3)**		0.7052	0.6492	0.0042	-	0.1400	0.0472	-	0.3785	0.2105	0.5403	5.0 / 6
	DERIVATION OF TRANSPORTATION CHARGES												
8	Pipeline Annual incl. some M12 (upstream	359,154	184,986	145,346	27	-	9,610	1,272	1,390	4,439	6,119	5,965	
	VOLUMES (10^3 m^3)												
9	Total Transportation Volumes	7,448,681	3,836,515	3,014,405	558	-	199,310	26,383	28,838	92,073	126,895	123,704	
10	**PROPOSED TRANSPORTATION CHARGE (¢/m^3)**		4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	

Witnesses: J. Collier
A. Kacicnik

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

RATE 135		
Seasonal Credits Applicable to Rate 135	**$**	**(422)**
Annual Volume (103 m3)		50,028
Mean Daily Volume (103 m3)		137
Annual Seasonal Credits	$	(3.08)
Payable from December to March	$	(0.77)
RATE 145		
Seasonal Credits Applicable to Rate 145	**$**	**(1,300)**
Annual Volume (103 m3)		237,331
Mean Daily Volume (103 m3)		
16 Hours		650
72 Hours		-
Annual Seasonal Credits		
16 Hours	$	(2.00)
Payable from December to March	$	(0.50)
72 Hours	$	(0.45)
Payable from December to March	$	(0.11)
Seasonal Credits Applicable to Rate 145		
16 Hours	$	(1,300.45)
72 Hours	$	-
RATE 170		
Seasonal Credits Applicable to Rate 170	**$**	**(6,790)**
Annual Volume (103 m3)		563,271
Mean Daily Volume (103 m3)		1,543
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)
RATE 200		
Seasonal Credits Applicable to Rate 200	**$**	**(105)**
Annual Volume (103 m3)		8,674
Mean Daily Volume (103 m3)		24
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

		Col. 1		Col. 2	Col. 3	Col. 4
				EB-2010-0146		
Item No.		Rate Block		Bills & Volumes	Rate	Revenues
		m³		10^3 m³	cents*	$000
	RATE 1					
1.1	Customer Charge	Bills		21,650,268	$19.00	411,355
1.2	Delivery Charge	first	30	621,360	7.3016	45,369
1.3		next	55	926,565	6.8312	63,295
1.4		next	85	1,016,069	6.4626	65,665
1.5		over	170	2,200,433	6.1882	136,167
1.	Total Distribution Charge			4,764,426		721,851
2.1	Gas Supply Load Balancing			4,764,426	0.7052	33,596
2.2	Gas Supply Transportation			3,836,515	4.8217	184,986
3.1	Gas Supply Commodity - System			3,356,349	15.4565	518,774
3.2	Gas Supply Commodity - Buy/Sell			0	15.4329	0
3.	Total Gas Supply Charge			3,356,349		518,774
4.1	TOTAL DISTRIBUTION			4,764,426		721,851
4.2	TOTAL GAS SUPPLY LOAD BALANCING			4,764,426		218,582
4.3	TOTAL GAS SUPPLY COMMODITY			3,356,349		518,774
4.	TOTAL RATE 1			**4,764,426**		1,459,208
5.	Adj. Factor		0.9999			
6.	ADJUSTED REVENUE					**1,459,122**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2010-0146		
Item No.		Rate Block m³	Bills & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 6				
1.1	Customer Charge	Bills	1,929,889	$65.00	125,443
1.2	Delivery Charge	First 500	569,624	6.9555	39,620
1.3		Next 1050	685,942	5.3171	36,472
1.4		Next 4500	1,210,064	4.1701	50,461
1.5		Next 7000	692,512	3.4329	23,773
1.6		Next 15250	564,404	3.1054	17,527
1.7		Over 28300	795,888	3.0233	24,062
1.	Total Distribution Charge		4,518,434		317,359
2.1	Gas Supply Load Balancing		4,518,434	0.6492	29,335
2.2	Gas Supply Transportation		3,014,405	4.8217	145,346
3.1	Gas Supply Commodity - System		2,235,728	15.5210	347,007
3.2	Gas Supply Commodity - Buy/Sell		0	15.4975	0
3.	Total Gas Supply Charge		2,235,728		347,007
4.1	TOTAL DISTRIBUTION		4,518,434		317,359
4.2	TOTAL GAS SUPPLY LOAD BALANCING		4,518,434		174,681
4.3	TOTAL GAS SUPPLY COMMODITY		2,235,728		347,007
4.	TOTAL RATE 6		**4,518,434**		839,048
5.	Adj. Factor	1.000			
6.	ADJUSTED REVENUE				**838,999**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2010-0146 Bills & Volumes 10³ m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 9				
1.1	Customer Charge	Bills	130	$235.89	31
1.2	Delivery Charge	first 20000	512	10.7649	55
1.3		over 20000	47	10.0762	5
1.	Total Distribution Charge		558		90
2.1	Gas Supply Load Balancing		558	0.0042	0
2.2	Gas Supply Transportation		558	4.8217	27
3.1	Gas Supply Commodity - System		408	15.3459	63
3.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
3.	Total Gas Supply Charge		408		63
4.1	TOTAL DISTRIBUTION		558		90
4.2	TOTAL GAS SUPPLY LOAD BALANCING		558		27
4.3	TOTAL GAS SUPPLY COMMODITY		408		63
4	TOTAL RATE 9		**558**		**180**

		Rate Block m³	EB-2010-0146 Contracts & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 100				
1.1	Customer Charge	Contracts	0	$122.01	0
1.2	Demand Charge		0	8.19	0
1.3	Delivery Charge	first 14,000	0	5.1296	0
1.4		next 28,000	0	3.7706	0
1.5		over 42,000	0	3.2116	0
1	Total Distribution Charge		0		0
2.1	Gas Supply Load Balancing		0	0.5055	0
2.2	Gas Supply Transportation		0	4.8217	0
3.1	Gas Supply Commodity - System		0	15.3599	0
3.2	Gas Supply Commodity - Buy/Sell		0	15.3412	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-2010-0146 Contracts & Volumes 10^3 m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 110				
1.1	Customer Charge	Contracts	2,448	$587.37	1,438
1.2	Demand Charge		27,320	22.9100	6,259
1.3	Delivery Charge	first 1,000,000	443,782	0.5996	2,661
1.4		over 1,000,000	28,073	0.4496	126
1.	Total Distribution Charge		471,855		10,484
2.1	Load Balancing Commodity		471,855	0.1400	661
2.2	Gas Supply Transportation		199,310	4.8217	9,610
2.	Total Gas Supply Load Balancing				10,271
3.1	Gas Supply Commodity - System		64,501	15.3459	9,898
3.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
3.	Total Gas Supply Charge		64,501		9,898
4.1	TOTAL DISTRIBUTION		471,855		10,484
4.2	TOTAL GAS SUPPLY LOAD BALANCING		471,855		10,271
4.3	TOTAL GAS SUPPLY COMMODITY		64,501		9,898
4.	TOTAL RATE 110		**471,855**		**30,654**

Item No.		Rate Block m³	EB-2010-0146 Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 115				
6.6	Customer Charge	Contracts	408	$622.62	254
6.2	Demand Charge		19,631	24.3600	4,782
6.3	Delivery Charge	first 1,000,000	162,230	0.3285	533
6.4		over 1,000,000	350,867	0.2285	802
6	Total Distribution Charge		513,097		6,371
7.1	Load Balancing Commodity		513,097	0.0472	242
7.2	Gas Supply Transportation		26,383	4.8217	1,272
7	Total Gas Supply Load Balancing				1,514
8.1	Gas Supply Commodity - System		410	15.3459	63
8.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
8.	Total Gas Supply Charge		410		63
9.1	TOTAL DISTRIBUTION		513,097		6,371
9.2	TOTAL GAS SUPPLY LOAD BALANCING		513,097		1,514
9.3	TOTAL GAS SUPPLY COMMODITY		410		63
9.	TOTAL RATE 115		**513,097**		**7,948**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2010-0146 Contracts & Volumes 10^3 m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 125				
1.1	Customer Charge		48	$ 500.00	24
1.2	Demand Charge		80,056	9.0768	7,267
1.	Total Distribution Charge		80,056		7,291

Item No.		Rate Block m³	EB-2010-0146 Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 135				
	DEC to MAR				
1.1	Customer Charge	Contracts	131	$115.08	15
1.2	Delivery Charge	first 14,000	530	6.7616	36
1.3		next 28,000	814	5.5616	45
1.4		over 42,000	2,458	5.1616	127
1.	Total Distribution Charge		3,802		223
2.1	Gas Supply Load Balancing		3,802	0.0000	0
2.2	Gas Supply Transportation		2,076	4.8217	100
2.3	Seasonal Credit				(422)
3.1	Gas Supply Commodity - System		67	15.4267	10
3.2	Gas Supply Commodity - Buy/Sell		0	15.4032	0
3.	Total Gas Supply Charge		67		10
4.	SUB-TOTAL WINTER				-88
	APR to NOV				
5.1	Customer Charge	Contracts	264	$115.08	30
5.2	Delivery Charge	first 14,000	3,504	2.0616	72
5.3		next 28,000	6,783	1.3616	92
5.4		over 42,000	35,939	1.1616	417
5.	Total Distribution Charge		46,226		612
6.1	Gas Supply Load Balancing		46,226	0.0000	0
6.2	Gas Supply Transportation		26,761	4.8217	1,290
7.1	Gas Supply Commodity - System		533	15.4267	82
7.2	Gas Supply Commodity - Buy/Sell		0	15.4032	0
7.	Total Gas Supply Charge		533		82
8.	SUB-TOTAL SUMMER				1,985
9.1	TOTAL DISTRIBUTION		50,028		835
9.2	TOTAL GAS SUPPLY LOAD BALANCING		50,028		969
9.3	TOTAL GAS SUPPLY COMMODITY		600		93
9.	TOTAL RATE 135		**50,028**		**1,897**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2010-0146		
Item No.		Rate Block m³	Contracts & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 145				
1.1	Customer Charge	Contracts	2,244	$123.34	277
1.2	Demand Charge		22,841	8.2300	1,880
1.2	Delivery Charge	first 14,000	29,784	2.8453	847
1.3		next 28,000	50,262	1.4863	747
1.4		over 42,000	157,285	0.9273	1,458
1.	Total Distribution Charge		237,331		5,209
2.1	Gas Supply Load Balancing		237,331	0.3785	898
2.2	Gas Supply Transportation		92,073	4.8217	4,439
2.3	Curtailment Credit				(1,300)
3.1	Gas Supply Commodity - System		22,339	15.5112	3,465
3.2	Gas Supply Commodity - Buy/Sell		0	15.4876	0
3.	Total Gas Supply Charge		22,339		3,465
4.1	TOTAL DISTRIBUTION		237,331		5,209
4.2	TOTAL GAS SUPPLY LOAD BALANCING		237,331		4,037
4.3	TOTAL GAS SUPPLY COMMODITY		22,339		3,465
4.	TOTAL RATE 145		**237,331**		**12,712**

			EB-2010-0146		
		Rate Block m³	Contracts & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 170				
6.6	Customer Charge	Contracts	468	$279.31	131
6.2	Demand Charge		50,890	4.0900	2,081
6.3	Delivery Charge	first 1,000,000	343,862	0.5242	1,802
6.4		over 1,000,000	219,408	0.3242	711
6	Total Distribution Charge		563,271		4,726
7.1	Gas Supply Load Balancing		563,271	0.2105	1,186
7.7	Gas Supply Transportation		126,895	4.8217	6,119
7.3	Curtailment Credit				(6,790)
8.1	Gas Supply Commodity - System		49,927	15.3459	7,662
8.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
8.	Total Gas Supply Charge		49,927		7,662
9.1	TOTAL DISTRIBUTION		563,271		4,726
9.2	TOTAL GAS SUPPLY LOAD BALANCING		563,271		514
9.3	TOTAL GAS SUPPLY COMMODITY		49,927		7,662
9.	TOTAL RATE 170		**563,271**		**12,902**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2010-0146 Contracts & Volumes 10³ m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 200				
1.1	Customer Charge	Contracts	12	$0.00	0
1.2	Demand Charge		13,334	14.7000	1,960
1.3	Delivery Charge		157,393	1.1289	1,777
1.	Total Distribution Charge		157,393		3,737
2.1	Gas Supply Load Balancing		157,393	0.5403	850
2.2	Gas Supply Transportation		123,704	4.8217	5,965
2.3	Curtailment Credit				(105)
3.1	Gas Supply Commodity - System		123,704	15.3459	18,984
3.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
3.	Total Gas Supply Charge		123,704		18,984
4.1	TOTAL DISTRIBUTION		157,393		3,737
4.2	TOTAL GAS SUPPLY LOAD BALANCING		157,393		6,710
4.3	TOTAL GAS SUPPLY COMMODITY		123,704		18,984
4.	TOTAL RATE 200		**157,393**		**29,431**

		Rate Block m³	EB-2010-0146 Contracts & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 300				
	Firm				
	Customer Charge		108	$500.00	54
	Demand Charge		1,005	24.9189	251
	Interruptible				
	Minimum Delivery Charge		30,000	0.3581	107
	Maximum Delivery Charge		0	0.9831	0
8.	TOTAL RATE 300		**0**		**412**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 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.	$	228.00	216.00	12.00	5.6%	228.00	216.00	12.00	5.6%
1.3	DISTRIBUTION CHG.	$	199.50	211.29	(11.79)	-5.6%	300.73	318.49	(17.76)	-5.6%
1.4	LOAD BALANCING	§ $	169.35	176.77	(7.42)	-4.2%	259.28	270.64	(11.36)	-4.2%
1.5	SALES COMMDTY	$	473.57	472.54	1.03	0.2%	725.06	723.47	1.59	0.2%
1.6	TOTAL SALES	$	1,070.42	1,076.60	(6.18)	-0.6%	1,513.07	1,528.60	(15.53)	-1.0%
1.7	TOTAL T-SERVICE	$	596.85	604.06	(7.21)	-1.2%	788.01	805.13	(17.12)	-2.1%
1.8	SALES UNIT RATE	$/m³	0.3494	0.3514	(0.0020)	-0.6%	0.3225	0.3259	(0.0033)	-1.0%
1.9	T-SERVICE UNIT RATE	$/m³	0.1948	0.1971	(0.0024)	-1.2%	0.1680	0.1716	(0.0036)	-2.1%
1.10	SALES UNIT RATE	$/GJ	9.269	9.323	(0.0535)	-0.6%	8.558	8.646	(0.0878)	-1.0%
1.11	T-SERVICE UNIT RATE	$/GJ	5.168	5.231	(0.0624)	-1.2%	4.457	4.554	(0.0968)	-2.1%

			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.	$	228.00	216.00	12.00	5.6%	228.00	216.00	12.00	5.6%
2.3	DISTRIBUTION CHG.	$	127.96	135.52	(7.56)	-5.6%	133.16	141.05	(7.89)	-5.6%
2.4	LOAD BALANCING	§ $	108.06	112.80	(4.74)	-4.2%	110.82	115.69	(4.87)	-4.2%
2.5	SALES COMMDTY	$	302.15	301.49	0.66	0.2%	309.92	309.23	0.69	0.2%
2.6	TOTAL SALES	$	766.17	765.81	0.36	0.0%	781.90	781.97	(0.07)	0.0%
2.7	TOTAL T-SERVICE	$	464.02	464.32	(0.30)	-0.1%	471.98	472.74	(0.76)	-0.2%
2.8	SALES UNIT RATE	$/m³	0.3919	0.3917	0.0002	0.0%	0.3900	0.3900	(0.0000)	0.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.2374	0.2375	(0.0002)	-0.1%	0.2354	0.2358	(0.0004)	-0.2%
2.10	SALES UNIT RATE	$/GJ	10.398	10.393	0.0049	0.0%	10.347	10.348	(0.0009)	0.0%
2.11	T-SERVICE UNIT RATE	$/GJ	6.297	6.302	(0.0041)	-0.1%	6.246	6.256	(0.0101)	-0.2%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	(B)	CHANGE (A) - (B)	CHANGE %	(A)	(B)	CHANGE (A) - (B)	CHANGE %
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	228.00	216.00	12.00	5.6%	228.00	216.00	12.00	5.6%
3.3	DISTRIBUTION CHG.	$	323.44	342.54	(19.10)	-5.6%	75.21	79.63	(4.42)	-5.6%
3.4	LOAD BALANCING	§ $	278.99	291.27	(12.28)	-4.2%	59.76	62.38	(2.62)	-4.2%
3.5	SALES COMMDTY	$	780.24	778.54	1.70	0.2%	167.08	166.72	0.36	0.2%
3.6	TOTAL SALES	$	1,610.67	1,628.35	(17.68)	-1.1%	530.05	524.73	5.32	1.0%
3.7	TOTAL T-SERVICE	$	830.43	849.81	(19.38)	-2.3%	362.97	358.01	4.96	1.4%
3.8	SALES UNIT RATE	$/m³	0.3191	0.3226	(0.0035)	-1.1%	0.4903	0.4854	0.0049	1.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1645	0.1683	(0.0038)	-2.3%	0.3358	0.3312	0.0046	1.4%
3.10	SALES UNIT RATE	$/GJ	8.466	8.559	(0.0929)	-1.1%	13.010	12.879	0.1306	1.0%
3.11	T-SERVICE UNIT RATE	$/GJ	4.365	4.467	(0.1019)	-2.3%	8.909	8.787	0.1217	1.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 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)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	780.00	720.00	60.00	8.3%	780.00	720.00	60.00	8.3%
1.3	DISTRIBUTION CHG.	$	1,189.97	1,232.01	(42.04)	-3.4%	1,526.77	1,580.74	(53.97)	-3.4%
1.4	LOAD BALANCING	§ $	1,236.77	1,295.49	(58.72)	-4.5%	1,601.78	1,677.86	(76.08)	-4.5%
1.5	SALES COMMDTY	$	3,508.66	3,505.72	2.94	0.1%	4,544.24	4,540.40	3.84	0.1%
1.6	TOTAL SALES	$	6,715.40	6,753.22	(37.82)	-0.6%	8,452.79	8,519.00	(66.21)	-0.8%
1.7	TOTAL T-SERVICE	$	3,206.74	3,247.50	(40.76)	-1.3%	3,908.55	3,978.60	(70.05)	-1.8%
1.8	SALES UNIT RATE	$/m³	0.2971	0.2987	(0.0017)	-0.6%	0.2887	0.2910	(0.0023)	-0.8%
1.9	T-SERVICE UNIT RATE	$/m³	0.1419	0.1437	(0.0018)	-1.3%	0.1335	0.1359	(0.0024)	-1.8%
1.10	SALES UNIT RATE	$/GJ	7.882	7.926	(0.0444)	-0.6%	7.660	7.720	(0.0600)	-0.8%
1.11	T-SERVICE UNIT RATE	$/GJ	3.764	3.812	(0.0478)	-1.3%	3.542	3.605	(0.0635)	-1.8%

			Medium Commercial Customer				Large Commercial Customer			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	780.00	720.00	60.00	8.3%	780.00	720.00	60.00	8.3%
2.3	DISTRIBUTION CHG.	$	6,408.09	6,634.63	(226.54)	-3.4%	11,732.92	12,147.68	(414.76)	-3.4%
2.4	LOAD BALANCING	§ $	9,276.70	9,717.24	(440.54)	-4.5%	18,553.33	19,434.44	(881.11)	-4.5%
2.5	SALES COMMDTY	$	26,317.88	26,295.65	22.23	0.1%	52,635.59	52,591.17	44.42	0.1%
2.6	TOTAL SALES	$	42,782.67	43,367.52	(584.85)	-1.3%	83,701.84	84,893.29	(1,191.45)	-1.4%
2.7	TOTAL T-SERVICE	$	16,464.79	17,071.87	(607.08)	-3.6%	31,066.25	32,302.12	(1,235.87)	-3.8%
2.8	SALES UNIT RATE	$/m³	0.2523	0.2558	(0.0034)	-1.3%	0.2468	0.2503	(0.0035)	-1.4%
2.9	T-SERVICE UNIT RATE	$/m³	0.0971	0.1007	(0.0036)	-3.6%	0.0916	0.0953	(0.0036)	-3.8%
2.10	SALES UNIT RATE	$/GJ	6.694	6.786	(0.0915)	-1.3%	6.549	6.642	(0.0932)	-1.4%
2.11	T-SERVICE UNIT RATE	$/GJ	2.576	2.671	(0.0950)	-3.6%	2.431	2.527	(0.0967)	-3.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 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.	$	780.00	720.00	60.00	8.3%	780.00	720.00	60.00	8.3%
3.3	DISTRIBUTION CHG.	$	2,109.64	2,184.20	(74.56)	-3.4%	2,829.44	2,929.43	(99.99)	-3.4%
3.4	LOAD BALANCING	§ $	2,368.10	2,480.56	(112.46)	-4.5%	3,496.10	3,662.12	(166.02)	-4.5%
3.5	SALES COMMDTY	$	6,718.28	6,712.61	5.67	0.1%	9,918.37	9,910.01	8.36	0.1%
3.6	TOTAL SALES	$	11,976.02	12,097.37	(121.35)	-1.0%	17,023.91	17,221.56	(197.65)	-1.1%
3.7	TOTAL T-SERVICE	$	5,257.74	5,384.76	(127.02)	-2.4%	7,105.54	7,311.55	(206.01)	-2.8%
3.8	SALES UNIT RATE	$/m³	0.2767	0.2795	(0.0028)	-1.0%	0.2664	0.2695	(0.0031)	-1.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1215	0.1244	(0.0029)	-2.4%	0.1112	0.1144	(0.0032)	-2.8%
3.10	SALES UNIT RATE	$/GJ	7.341	7.415	(0.0744)	-1.0%	7.068	7.150	(0.0821)	-1.1%
3.11	T-SERVICE UNIT RATE	$/GJ	3.223	3.301	(0.0779)	-2.4%	2.950	3.036	(0.0855)	-2.8%

			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.	$	780.00	720.00	60.00	8.3%	780.00	720.00	60.00	8.3%
4.3	DISTRIBUTION CHG.	$	6,562.26	6,794.21	(231.95)	-3.4%	11,847.49	12,266.26	(418.77)	-3.4%
4.4	LOAD BALANCING	§ $	9,276.70	9,717.23	(440.53)	-4.5%	18,553.30	19,434.35	(881.05)	-4.5%
4.5	SALES COMMDTY	$	26,317.86	26,295.67	22.19	0.1%	52,635.45	52,591.01	44.44	0.1%
4.6	TOTAL SALES	$	42,936.82	43,527.11	(590.29)	-1.4%	83,816.24	85,011.62	(1,195.38)	-1.4%
4.7	TOTAL T-SERVICE	$	16,618.96	17,231.44	(612.48)	-3.6%	31,180.79	32,420.61	(1,239.82)	-3.8%
4.8	SALES UNIT RATE	$/m³	0.2532	0.2567	(0.0035)	-1.4%	0.2472	0.2507	(0.0035)	-1.4%
4.9	T-SERVICE UNIT RATE	$/m³	0.0980	0.1016	(0.0036)	-3.6%	0.0919	0.0956	(0.0037)	-3.8%
4.10	SALES UNIT RATE	$/GJ	6.719	6.811	(0.0924)	-1.4%	6.558	6.651	(0.0935)	-1.4%
4.11	T-SERVICE UNIT RATE	$/GJ	2.600	2.696	(0.0958)	-3.6%	2.440	2.537	(0.0970)	-3.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
1.2	CUSTOMER CHG.	$	1,464.12	1,458.24	5.88	0.4%	1,464.12	1,458.24	5.88	0.4%
1.3	DISTRIBUTION CHG.	$	17,651.17	17,607.19	43.98	0.2%	28,091.73	28,014.10	77.63	0.3%
1.4	LOAD BALANCING	$	18,069.27	18,943.75	(874.48)	-4.6%	31,886.99	33,430.20	(1,543.21)	-4.6%
1.5	SALES COMMDTY	$	52,098.82	52,054.84	43.98	0.1%	91,939.23	91,861.64	77.59	0.1%
1.6	TOTAL SALES	$	89,283.38	90,064.02	(780.64)	-0.9%	153,382.07	154,764.18	(1,382.11)	-0.9%
1.7	TOTAL T-SERVICE	$	37,184.56	38,009.18	(824.62)	-2.2%	61,442.84	62,902.54	(1,459.70)	-2.3%
1.8	SALES UNIT RATE	$/m³	0.2632	0.2655	(0.0023)	-0.9%	0.2562	0.2586	(0.0023)	-0.9%
1.9	T-SERVICE UNIT RATE	$/m³	0.1096	0.1121	(0.0024)	-2.2%	0.1026	0.1051	(0.0024)	-2.3%
1.10	SALES UNIT RATE	$/GJ	6.984	7.045	(0.0611)	-0.9%	6.799	6.860	(0.0613)	-0.9%
1.11	T-SERVICE UNIT RATE	$/GJ	2.909	2.973	(0.0645)	-2.2%	2.724	2.788	(0.0647)	-2.3%
			Rate 100 - Small Industrial Firm				**Rate 100 - Average Industrial Firm**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
2.2	CUSTOMER CHG.	$	1,464.12	1,458.24	5.88	0.4%	1,464.12	1,458.24	5.88	0.4%
2.3	DISTRIBUTION CHG.	$	17,923.96	17,880.01	43.95	0.2%	28,333.17	28,255.52	77.65	0.3%
2.4	LOAD BALANCING	$	18,069.27	18,943.74	(874.47)	-4.6%	31,886.93	33,430.13	(1,543.20)	-4.6%
2.5	SALES COMMDTY	$	52,098.83	52,054.83	44.00	0.1%	91,939.08	91,861.48	77.60	0.1%
2.6	TOTAL SALES	$	89,556.18	90,336.82	(780.64)	-0.9%	153,623.30	155,005.37	(1,382.07)	-0.9%
2.7	TOTAL T-SERVICE	$	37,457.35	38,281.99	(824.64)	-2.2%	61,684.22	63,143.89	(1,459.67)	-2.3%
2.8	SALES UNIT RATE	$/m³	0.2640	0.2663	(0.0023)	-0.9%	0.2567	0.2590	(0.0023)	-0.9%
2.9	T-SERVICE UNIT RATE	$/m³	0.1104	0.1129	(0.0024)	-2.2%	0.1031	0.1055	(0.0024)	-2.3%
2.10	SALES UNIT RATE	$/GJ	7.005	7.066	(0.0611)	-0.9%	6.810	6.871	(0.0613)	-0.9%
2.11	T-SERVICE UNIT RATE	$/GJ	2.930	2.995	(0.0645)	-2.2%	2.734	2.799	(0.0647)	-2.3%

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 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.	$	1,480.08	1,472.76	7.32	0.5%	1,480.08	1,472.76	7.32	0.5%
3.3	DISTRIBUTION CHG.	$	9,917.29	9,882.98	34.31	0.3%	14,439.98	14,379.38	60.60	0.4%
3.4	LOAD BALANCING	$	15,778.06	16,677.87	(899.81)	-5.4%	27,844.06	29,432.02	(1,587.96)	-5.4%
3.5	SALES COMMDTY	$	52,612.13	52,447.29	164.84	0.3%	92,845.09	92,554.17	290.92	0.3%
3.6	TOTAL SALES	$	79,787.56	80,480.90	(693.34)	-0.9%	136,609.21	137,838.33	(1,229.12)	-0.9%
3.7	TOTAL T-SERVICE	$	27,175.43	28,033.61	(858.18)	-3.1%	43,764.12	45,284.16	(1,520.04)	-3.4%
3.8	SALES UNIT RATE	$/m³	0.2352	0.2373	(0.0020)	-0.9%	0.2282	0.2303	(0.0021)	-0.9%
3.9	T-SERVICE UNIT RATE	$/m³	0.0801	0.0826	(0.0025)	-3.1%	0.0731	0.0757	(0.0025)	-3.4%
3.10	SALES UNIT RATE	$/GJ	6.241	6.295	(0.0542)	-0.9%	6.055	6.110	(0.0545)	-0.9%
3.11	T-SERVICE UNIT RATE	$/GJ	2.126	2.193	(0.0671)	-3.1%	1.940	2.007	(0.0674)	-3.4%

			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.	$	1,480.08	1,472.76	7.32	0.5%	1,480.08	1,472.76	7.32	0.5%
4.3	DISTRIBUTION CHG.	$	10,190.11	10,155.78	34.33	0.3%	14,681.42	14,620.84	60.58	0.4%
4.4	LOAD BALANCING	$	15,778.07	16,677.87	(899.80)	-5.4%	27,844.02	29,431.92	(1,587.90)	-5.4%
4.5	SALES COMMDTY	$	52,612.12	52,447.30	164.82	0.3%	92,844.93	92,554.03	290.90	0.3%
4.6	TOTAL SALES	$	80,060.38	80,753.71	(693.33)	-0.9%	136,850.45	138,079.55	(1,229.10)	-0.9%
4.7	TOTAL T-SERVICE	$	27,448.26	28,306.41	(858.15)	-3.0%	44,005.52	45,525.52	(1,520.00)	-3.3%
4.8	SALES UNIT RATE	$/m³	0.2360	0.2381	(0.0020)	-0.9%	0.2286	0.2307	(0.0021)	-0.9%
4.9	T-SERVICE UNIT RATE	$/m³	0.0809	0.0835	(0.0025)	-3.0%	0.0735	0.0761	(0.0025)	-3.3%
4.10	SALES UNIT RATE	$/GJ	6.263	6.317	(0.0542)	-0.9%	6.066	6.121	(0.0545)	-0.9%
4.11	T-SERVICE UNIT RATE	$/GJ	2.147	2.214	(0.0671)	-3.0%	1.951	2.018	(0.0674)	-3.3%

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 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.	$	7,048.44	7,020.00	28.44	0.4%	7,048.44	7,020.00	28.44	0.4%
5.3	DISTRIBUTION CHG.	$	12,639.18	12,592.60	46.58	0.4%	206,877.38	206,101.24	776.14	0.4%
5.4	LOAD BALANCING	$	29,699.49	31,349.60	(1,650.11)	-5.3%	494,991.06	522,492.59	(27,501.53)	-5.3%
5.5	SALES COMMDTY	$	91,855.65	91,483.33	372.32	0.4%	1,530,925.54	1,524,720.40	6,205.14	0.4%
5.6	TOTAL SALES	$	141,242.76	142,445.53	(1,202.77)	-0.8%	2,239,842.42	2,260,334.23	(20,491.81)	-0.9%
5.7	TOTAL T-SERVICE	$	49,387.11	50,962.20	(1,575.09)	-3.1%	708,916.88	735,613.83	(26,696.95)	-3.6%
5.8	SALES UNIT RATE	$/m³	0.2360	0.2380	(0.0020)	-0.8%	0.2245	0.2266	(0.0021)	-0.9%
5.9	T-SERVICE UNIT RATE	$/m³	0.0825	0.0851	(0.0026)	-3.1%	0.0711	0.0737	(0.0027)	-3.6%
5.10	SALES UNIT RATE	$/GJ	6.261	6.314	(0.0533)	-0.8%	5.957	6.012	(0.0545)	-0.9%
5.11	T-SERVICE UNIT RATE	$/GJ	2.189	2.259	(0.0698)	-3.1%	1.885	1.956	(0.0710)	-3.6%

			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.	$	7,048.44	7,020.00	28.44	0.4%	7,471.44	7,450.32	21.12	0.3%
6.3	DISTRIBUTION CHG.	$	159,919.49	159,143.32	776.17	0.5%	870,006.18	867,678.55	2,327.63	0.3%
6.4	LOAD BALANCING	$	494,991.01	522,492.52	(27,501.51)	-5.3%	3,400,109.00	3,595,697.03	(195,588.03)	-5.4%
6.5	SALES COMMDTY	$	1,530,925.39	1,524,720.26	6,205.13	0.4%	10,716,479.30	10,673,043.29	43,436.01	0.4%
6.6	TOTAL SALES	$	2,192,884.33	2,213,376.10	(20,491.77)	-0.9%	14,994,065.92	15,143,869.19	(149,803.27)	-1.0%
6.7	TOTAL T-SERVICE	$	661,958.94	688,655.84	(26,696.90)	-3.9%	4,277,586.62	4,470,825.90	(193,239.28)	-4.3%
6.8	SALES UNIT RATE	$/m³	0.2198	0.2219	(0.0021)	-0.9%	0.2147	0.2169	(0.0021)	-1.0%
6.9	T-SERVICE UNIT RATE	$/m³	0.0664	0.0690	(0.0027)	-3.9%	0.0613	0.0640	(0.0028)	-4.3%
6.10	SALES UNIT RATE	$/GJ	5.832	5.887	(0.0545)	-0.9%	5.697	5.754	(0.0569)	-1.0%
6.11	T-SERVICE UNIT RATE	$/GJ	1.761	1.832	(0.0710)	-3.9%	1.625	1.699	(0.0734)	-4.3%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 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.	$	1,380.96	1,377.84	3.12	0.2%	3,351.72	3,339.24	12.48	0.4%
7.3	DISTRIBUTION CHG.	$	8,377.3	8,355.73	21.60	0.3%	77,349.2	77,045.14	304.10	0.4%
7.4	LOAD BALANCING	$	23,815.72	25,506.75	(1,691.03)	-6.6%	381,761.00	409,135.98	(27,374.98)	-6.7%
7.5	SALES COMMDTY	$	92,339.14	91,857.29	481.85	0.5%	1,530,925.54	1,524,720.40	6,205.14	0.4%
7.6	TOTAL SALES	$	125,913.15	127,097.61	(1,184.46)	-0.9%	1,993,387.50	2,014,240.76	(20,853.26)	-1.0%
7.7	TOTAL T-SERVICE	$	33,574.01	35,240.32	(1,666.31)	-4.7%	462,461.96	489,520.36	(27,058.40)	-5.5%
7.8	SALES UNIT RATE	$/m³	0.2104	0.2123	(0.0020)	-0.9%	0.1998	0.2019	(0.0021)	-1.0%
7.9	T-SERVICE UNIT RATE	$/m³	0.0561	0.0589	(0.0028)	-4.7%	0.0464	0.0491	(0.0027)	-5.5%
7.10	SALES UNIT RATE	$/GJ	5.581	5.634	(0.0525)	-0.9%	5.302	5.357	(0.0555)	-1.0%
7.11	T-SERVICE UNIT RATE	$/GJ	1.488	1.562	(0.0739)	-4.7%	1.230	1.302	(0.0720)	-5.5%

Item No.			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.	$	3,351.72	3,339.24	12.48	0.4%	3,351.72	3,339.24	12.48	0.4%
8.3	DISTRIBUTION CHG.	$	70,164.4	69,860.30	304.09	0.4%	375,582.5	373,453.87	2,128.60	0.6%
8.4	LOAD BALANCING	$	381,760.94	409,135.93	(27,374.99)	-6.7%	2,672,327.02	2,863,951.93	(191,624.91)	-6.7%
8.5	SALES COMMDTY	$	1,530,925.39	1,524,720.26	6,205.13	0.4%	10,716,479.30	10,673,043.29	43,436.01	0.4%
8.6	TOTAL SALES	$	1,986,202.44	2,007,055.73	(20,853.29)	-1.0%	13,767,740.51	13,913,788.33	(146,047.82)	-1.0%
8.7	TOTAL T-SERVICE	$	455,277.05	482,335.47	(27,058.42)	-5.6%	3,051,261.21	3,240,745.04	(189,483.83)	-5.8%
8.8	SALES UNIT RATE	$/m³	0.1991	0.2012	(0.0021)	-1.0%	0.1972	0.1992	(0.0021)	-1.0%
8.9	T-SERVICE UNIT RATE	$/m³	0.0456	0.0483	(0.0027)	-5.6%	0.0437	0.0464	(0.0027)	-5.8%
8.10	SALES UNIT RATE	$/GJ	5.282	5.338	(0.0555)	-1.0%	5.231	5.286	(0.0555)	-1.0%
8.11	T-SERVICE UNIT RATE	$/GJ	1.211	1.283	(0.0720)	-5.6%	1.159	1.231	(0.0720)	-5.8%

Witnesses: J. Collier
A. Kacicnik

Measure of 2011 Revenues vs 2011 Revenue Requirement
December 31, 2011
(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col.10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Sales and Delivery Revenue	2,406.02	1,459.12	839.00	0.18	0.00	30.65	7.95	7.29	1.90	12.71	12.90	29.43	0.41	1.60	2.87
2.	Unbilled Revenues	(1.12)	(0.60)	(0.57)	0.00	0.00	(0.02)	0.00	0.00	(0.01)	0.08	(0.00)	0.00	0.00	0.00	0.00
3.	Total Revenues	2,404.89	1,458.52	838.43	0.18	0.00	30.63	7.95	7.29	1.89	12.79	12.90	29.43	0.41	1.60	2.87
4.	Proposed 2011 Revenue Requirement	2,404.89	1,454.73	838.39	0.25	0.00	31.36	7.96	7.34	1.82	14.38	14.32	29.41	0.46	1.60	2.87
5.	Measure of Revenues vs Revenue Requirement	1.00	1.00	1.00	0.71	0.00	0.98	1.00	0.99	1.03	0.89	0.90	1.00	0.89	1.00	1.00

Measure of 2011 Revenues vs 2011 Revenue Requirement
Excluding Gas Supply Commodity
December 31, 2011
(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col.10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Sales and Delivery Revenue	1,500.01	940.35	491.99	0.12	0.00	20.75	7.89	7.29	1.80	9.25	5.24	10.45	0.41	1.60	2.87
2.	Unbilled Revenues	(1.12)	(0.60)	(0.57)	0.00	0.00	(0.02)	0.00	0.00	(0.01)	0.08	(0.00)	0.00	0.00	0.00	0.00
3.	Total Revenues	1,498.88	939.75	491.42	0.12	0.00	20.74	7.89	7.29	1.80	9.32	5.24	10.45	0.41	1.60	2.87
4.	Proposed 2011 Revenue Requirement	1,498.89	935.96	491.39	0.19	0.00	21.46	7.89	7.34	1.73	10.91	6.66	10.42	0.46	1.60	2.87
5.	Measure of Revenues vs Revenue Requirement excluding Gas Supply Commodity	1.00	1.00	1.00	0.61	0.00	0.97	1.00	0.99	1.04	0.85	0.79	1.00	0.89	1.00	1.00

Total 2011 Revenue Requirement
December 31, 2011

(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	Reference
1	PRODUCT COSTS	906.0	518.8	347.0	0.1	-	9.9	0.1	-	0.1	3.5	7.7	19.0	-	-	-	Ex.B/T3/S10/P4/L1 & Ex.B/T3/S10/P5/L1
2	PIPELINE TRANS. AND LOAD BALANCING	417.7	218.9	174.7	0.0	-	10.2	1.4	-	1.4	4.0	0.4	6.7	-	-	-	Ex.B/T3/S10/P4/L2 & Ex.B/T3/S10/P5/L2
3	STORAGE	152.6	79.7	67.0	0.0	-	1.3	0.5	-	(0.4)	1.2	1.6	1.8	-	-	-	Ex.B/T3/S10/P4/L3 & Ex.B/T3/S10/P5/L3
4	DISTRIBUTION	469.8	276.7	161.9	0.0	-	8.2	5.5	6.9	0.1	4.7	4.0	1.3	0.3	0.1	-	Ex.B/T3/S10/P4/L4 & Ex.B/T3/S10/P5/L4
5	CUSTOMER RELATED	457.2	360.7	87.8	0.2	0.0	1.8	0.6	0.4	0.7	1.0	0.7	0.6	0.1	0.0	2.9	Ex.B/T3/S10/P5/L5
Total 2011 Revenue Requirement		2,403.3	1,454.7	838.4	0.3	0.0	31.4	8.0	7.3	1.8	14.4	14.3	29.4	0.3	0.1	2.9	

2011 Gas Cost to Operations Revenue Requirement

December 31, 2011

(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	896.0	513.7	342.2	0.1	-	9.9	0.1	-	0.1	3.4	7.6	18.9	-	-	-	1.1
1	Total Gas Cost	896.0	513.7	342.2	0.1	-	9.9	0.1	-	0.1	3.4	7.6	18.9	-	-	-	-
	PIPELINE TRANS. AND LOAD BALANCING																
2.1	Peak	12.0	6.5	5.2	-	-	0.1	0.0	-	-	-	-	0.1	-	-	-	3.1
2.2	Seasonal	22.8	11.3	10.0	0.0	-	0.2	0.1	-	-	0.4	0.5	0.3	-	-	-	3.2
2.3	Annual - Transportation	362.9	186.9	146.9	0.0	-	9.7	1.3	-	1.4	4.5	6.2	6.0	-	-	-	1.4
2.4	Seasonal Credit	(8.2)	-	-	-	-	-	-	-	-	(1.3)	(6.8)	(0.1)	-	-	-	-
2	Total Pipeline Trans. Cost	389.5	204.7	162.1	0.0	-	10.0	1.4	-	1.4	3.6	(0.1)	6.3	-	-	-	-
	STORAGE																
3.1	Deliverability	60.1	32.9	26.2	-	-	0.4	0.1	-	-	-	-	0.6	-	-	-	3.1
3.2	Space	57.5	28.4	25.3	0.0	-	0.6	0.2	-	-	0.9	1.2	0.8	-	-	-	3.2
3.3	Seasonal Credit	(0.4)	-	-	-	-	-	-	-	(0.4)	-	-	-	-	-	-	-
3	Total Storage	117.2	61.3	51.5	0.0	-	1.0	0.4	-	(0.4)	0.9	1.2	1.4	-	-	-	-
	DISTRIBUTION																
4.1	Commodity	13.3	5.6	5.3	0.0	-	0.6	0.6	-	0.1	0.3	0.7	0.2	-	-	-	1.3
4	Total Distribution	13.3	5.6	5.3	0.0	-	0.6	0.6	-	0.1	0.3	0.7	0.2	-	-	-	-
	Total 2011 Gas Cost to Operations Revenue Requirement	1,416.0	785.3	561.2	0.1	-	21.4	2.4	-	1.1	8.2	9.4	26.8	-	-	-	-

2011 Distribution Revenue Requirement
December 31, 2011

(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	10.0	5.1	4.8	0.0	-	0.0	0.0	-	0.0	0.0	0.0	0.0	-	-	-
2	LOAD BALANCING RELATED	28.2	14.2	12.6	(0.0)	-	0.2	(0.0)	-	(0.0)	0.4	0.5	0.4	-	-	-
	FACILITIES' COSTS															
3	STORAGE	35.3	18.5	15.5	0.0	-	0.3	0.1	-	-	0.3	0.3	0.4	-	-	-
4	DISTRIBUTION	456.4	271.0	156.5	0.0	-	7.7	4.9	6.9	0.0	4.5	3.3	1.2	0.3	0.1	-
5	CUSTOMER RELATED	457.2	360.7	87.8	0.2	0.0	1.8	0.6	0.4	0.7	1.0	0.7	0.6	0.1	0.0	2.9
	Total 2011 Distribution Revenue Requirement	987.2	669.4	277.2	0.2	0.0	9.9	5.5	7.3	0.7	6.2	4.9	2.6	0.3	0.1	2.9

2011 Y- Factor Revenue Requirement
December 31, 2011
(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	2011 Gas in Storage and Working Cash Carrying Cost	30.9	15.3	13.6	0.0	0.0	0.3	0.1	0.0	0.0	0.5	0.7	0.4	0.0	0.0		3.2
1.2	DSM 2011	26.7	10.3	9.9	0.0	0.0	1.7	1.5	0.0	0.0	1.6	1.8	0.0	0.0	0.0		Direct
1.3	CIS/ Customer Care 2011	97.4	89.4	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		4.1
		155.0	114.9	31.5	0.0	0.0	2.0	1.6	0.0	0.0	2.1	2.4	0.4	0.0	0.0		
	Y Factor: Capital Investment																
1.4	2011 Leave to Construct	3.5	1.7	1.4	0.0	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0		2.1
		3.5	1.7	1.4	0.0	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0		
1.5	**Total Y-Factor: Other & Capital Investment**	158.5	116.6	32.9	0.0	0.0	2.1	1.6	0.2	0.0	2.2	2.5	0.5	0.0	0.0		

2011 Distribution Revenue Requirement with Y- Factor Detail
December 31, 2011
(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 Firm	RATE 300 Int	DIRECT PURCHASE
1.0	DRR before Y- Factors	828.7	552.8	244.3	0.2	0.0	7.9	3.9	7.1	0.7	4.0	2.4	2.1	0.3	0.1	2.9
	Y Factor: Other															
1.1	2011 Gas in Storage and Working Cash Carrying Cost	30.9	15.3	13.6	0.0	0.0	0.3	0.1	0.0	0.0	0.5	0.7	0.4	0.0	0.0	0.0
1.2	DSM 2011	26.7	10.3	9.9	0.0	0.0	1.7	1.5	0.0	0.0	1.6	1.8	0.0	0.0	0.0	0.0
1.3	CIS/ Customer Care 2011	97.4	89.4	8.0	0.0	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	3.5	1.7	1.4	0.0	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.5	Total Y-Factor	158.5	116.6	32.9	0.0	0.0	2.1	1.6	0.2	0.0	2.2	2.5	0.5	0.0	0.0	0.0
1.6	DRR with Y-Factors	987.2	669.4	277.2	0.2	0.0	9.9	5.5	7.3	0.7	6.2	4.9	2.6	0.3	0.1	2.9

Allocators
December 31, 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
	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	5,854.0	3,356.3	2,235.7	0.4	0.0	64.5	0.4	0.0	0.6	22.3	49.9	123.7	0.0	0.0	0.0
1.2 Bundled Annual Deliveries	11,276.4	4,764.4	4,518.4	0.6	0.0	471.9	513.1	0.0	50.0	237.3	563.3	157.4	0.0	0.0	0.0
1.3 Total Annual Deliveries	11,306.4	4,764.4	4,518.4	0.6	0.0	471.9	513.1	0.0	50.0	237.3	563.3	157.4	0.0	30.0	0.0
1.4 Bundled Transportation Deliveries	7,448.7	3,836.5	3,014.4	0.6	0.0	199.3	26.4	0.0	28.8	92.1	126.9	123.7	0.0	0.0	0.0
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	104,967.1	49,494.0	42,630.5	3.5	0.0	1,779.5	1,592.5	7,148.9	5.1	729.6	303.2	1,190.7	89.8	0.0	0.0
2.2 Delivery Demand HP	96,715.5	49,494.0	42,630.5	3.5	0.0	1,779.5	1,592.5	0.0	5.1	729.6	303.2	0.0	89.8	88.1	0.0
2.3 Delivery Demand LP	95,626.8	49,494.0	42,630.5	3.5	0.0	1,779.5	503.7	0.0	5.1	729.6	303.2	0.0	89.8	88.1	0.0
2.4 Cust. Rel Plant	1,965,538.0	1,804,189.0	160,827.0	11.0	0.0	204.0	34.0	4.0	33.0	187.0	39.0	1.0	8.0	1.0	0.0
STORAGE RESPONSIBILITY															
3.1 Deliverability	51.9	28.3	22.6	0.0	0.0	0.3	0.1	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0
3.2 Space	2,623.0	1,295.1	1,154.4	0.0	0.0	28.2	10.4	0.0	0.0	43.0	56.8	35.1	0.0	0.0	0.0
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1,965,538.0	1,804,189.0	160,827.0	11.0	0.0	204.0	34.0	4.0	33.0	187.0	39.0	1.0	8.0	1.0	0.0
4.2 Services	1,900,200.0	1,687,622.7	209,500.1	13.7	0.0	1,012.2	284.4	2.4	206.6	908.5	590.7	0.0	43.4	15.1	0.0

Allocation Percentages
December 31, 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
	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	0.5733	0.3819	0.0001	0.0000	0.0110	0.0001	0.0000	0.0001	0.0038	0.0085	0.0211	0.0000	0.0000	0.0000
1.2 Bundled Annual Deliveries	1.0000	0.4225	0.4007	0.0000	0.0000	0.0418	0.0455	0.0000	0.0044	0.0210	0.0500	0.0140	0.0000	0.0000	0.0000
1.3 Total Annual Deliveries	1.0000	0.4214	0.3996	0.0000	0.0000	0.0417	0.0454	0.0000	0.0044	0.0210	0.0498	0.0139	0.0000	0.0027	0.0000
1.4 Bundled Transportation Deliveries	1.0000	0.5151	0.4047	0.0001	0.0000	0.0268	0.0035	0.0000	0.0039	0.0124	0.0170	0.0166	0.0000	0.0000	0.0000
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	1.0000	0.4715	0.4061	0.0000	0.0000	0.0170	0.0152	0.0681	0.0000	0.0070	0.0029	0.0113	0.0009	0.0000	0.0000
2.2 Delivery Demand HP	1.0000	0.5117	0.4408	0.0000	0.0000	0.0184	0.0165	0.0000	0.0001	0.0075	0.0031	0.0000	0.0009	0.0009	0.0000
2.3 Delivery Demand LP	1.0000	0.5176	0.4458	0.0000	0.0000	0.0186	0.0053	0.0000	0.0001	0.0076	0.0032	0.0000	0.0009	0.0009	0.0000
2.4 Cust. Rel Plant	1.0000	0.9179	0.0818	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	0.5463	0.4360	0.0000	0.0000	0.0059	0.0020	0.0000	0.0000	0.0000	0.0000	0.0098	0.0000	0.0000	0.0000
3.2 Space	1.0000	0.4937	0.4401	0.0000	0.0000	0.0108	0.0040	0.0000	0.0000	0.0164	0.0216	0.0134	0.0000	0.0000	0.0000
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1.0000	0.9179	0.0818	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	0.8881	0.1103	0.0000	0.0000	0.0005	0.0001	0.0000	0.0001	0.0005	0.0003	0.0000	0.0000	0.0000	0.0000

GAS COSTS, TRANSPORTATION, AND STORAGE

1. The purpose of this evidence is to provide an overview of the gas cost consequences of the gas supply activities, including storage and transportation, of Enbridge Gas Distribution Inc. (the “Company” or “Enbridge”) during the 2011 Test Year. The process for calculating budgeted gas costs is consistent with prior years. Using the forecasted volumetric demand requirements, the Company develops a gas supply plan using a model known as “SENDOUT”. This model determines the optimum monthly supply portfolio using existing contractual parameters, i.e., transportation contracts including storage deliverability, and also provides the Company with a forecast of monthly storage targets. Once the monthly supply portfolio and storage targets have been established then gas costs can be calculated.

Gas Supply

2. Enbridge expects to acquire its system gas supply under the following types of contracts during the Test Year:

- Western Canadian Supplies: These supplies source gas in the supply area of Western Canada and will be transported either via TransCanada PipeLines Limited (“TransCanada”) or via Alliance Pipeline to the Company’s franchise area.
- Ontario Production: The Ontario supply is *de minimus* in relative terms.
- Peaking contracts: These contracts source gas from other suppliers in the Eastern Zone during the winter season.
- Chicago Supply: These supplies are to be acquired in Chicago and transported to Dawn via the Company’s contracted capacity on the Vector Pipeline.

- Delivered Supply: These supplies are forecasted to be acquired directly at Dawn. However, the Company may consider alternative sources such as western Canadian supply utilizing TCPL STFT capacity either for economic or operational reasons.

Enbridge currently buys all of its gas on an indexed basis. It does not have any existing contracts that provide supply on a fixed price basis. The Company expects to continue this practice for its 2011 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	2 706.1	95.5
Ontario Production	1.5	0.0
Peaking	52.4	1.9
Chicago Supply	1 846.5	65.2
Delivered Supply	1 463.9	51.7
	6 070.4	214.3

Commodity Costs

4. The price assumptions reflect the market's assessment (as at the time of preparation of this evidence) of the different expected delivery points for the Company's forecast of gas supply.

5. The market's assessment is determined at any point in time by the use of the simple average of forward quoted prices as reported by various media and other services, over a period of 21 business days for a basket of pricing points, and pricing indices that reflect the Company's gas supply acquisition arrangements.

6. The Company prepared its gas supply forecast based upon a 21-day average of various indices from August 3, 2010 to August 31, 2010 for the 12 months commencing January 1, 2011 and applied these monthly prices to the 2011 budgeted annual volume gas purchases.

7. In an effort to remove the impact of commodity cost changes, the Company removed the impact of the updated price forecast and the October 1, 2010 QRAM prices in a fashion similar to the 2010 Budget that was filed in EB-2009-0172 at Exhibit B, Tab 6, Schedule 1.

8. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2011 PGVA. Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2011 PGVA. While the Company does not anticipate acquiring gas in 2011 via means other than the traditional transportation paths (i.e, TCPL, Alliance/Vector) the possibility does exist in the future to acquire gas via alternative means (i.e., Shale Gas, Rockies, etc.).

Peak Day Coverage

9. Enbridge continues to plan for its peak day coverage based on the 20% probability, multi-peak day design conditions introduced in the EBRO 490 proceeding. These conditions assume 39.5 degree days (Celsius) for the coldest peak. These conditions are experienced, on average, about once every five years. Enbridge is forecasting a design peak day level of 98 300 10^3m^3 (3.5 Bcf) during the winter season of the test year.

<u>Transportation</u>

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 2011 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 the following exceptions. 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. During 2010 the Company administered a TCPL FT Turnback process with its Direct Purchase customers and the outcome of those requests has been incorporated into the contracted TCPL capacity for November 1, 2010. The Company and intervenors participated in a System Reliability consultative and hearing (EB-2010-0231). The outcome of that proceeding has been included as a component of the 2011 gas supply portfolio.

11. As per the EB-2010-0231 Settlement Agreement, the Company assigned 50,000 Gj/day of TCPL shorthaul capacity to Direct Purchase customers and plans to acquire 50,000 Gj/day of TCPL STFT from November to March. The Company also incorporated in its plan the acquisition of 200,000 Gj/day of TCPL STFT for three winter months which was also agreed upon as part of the settlement agreement. The Company has also taken an assignment of 40,000 Gj/day of TCPL-FT Dawn to Iroquois capacity.

12. The Company also has M12 service entitlements with Union Gas totaling 2,225,102 GJ/d (2,081 MMcf/d) for delivery of gas by Union at Dawn for storage

injection or onward transportation, for gas withdrawn from storage at Tecumseh or Union, or both, and for gas sourced in Western Canada or the United States, or both, and delivered at Dawn for onward transportation. The Company also has M16 transportation capacity with Union to facilitate the Chatham "D" Storage facility. The gas cost forecast assumed January 1, 2010 Union tolls.

Storage

13. The Company has underground storage of its own at Tecumseh near Corunna in southwestern Ontario and at Crowland near Welland in the Niagara Region. Tecumseh is a large multiple-cycle facility, whereas Crowland is a small peak shaving facility.

14. Enbridge also held a storage entitlement with Union Gas Limited for 21,259,700 GJ broken down into three contracts with varied expiry dates. In its decision in the NGEIR proceeding dated November 7, 2006, the Board ruled that a phased in approach to market based storage was in the best interests of customers in Ontario. Effective April 1, 2010 all of the Company's contracted third party storage is at market based rates.

15. During 2010 the Company issued an RFP for two market based storage contracts that expire March 31, 2011. The cost consequences of these and the other third party storage contracts have been included in the forecast for 2011 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.

Witness: D. Small

<u>Schedules</u>

16. Pages 1 and 2 of Exhibit B, Tab 4, Schedule 2 provide the summary of the forecasted gas cost to operations for 2011 based upon an updated supply and transportation portfolio to meet the forecasted volumetric requirement for 2011. Page 3 provides a breakdown of the forecasted 2011 storage and transportation costs that are shown at Item #13, Column 2 of page 2. Page 4 provides a breakdown of the monthly gas in storage balances for rate base purposes in 2011. Pages 5 through 8 are the comparable schedules for 2010 which incorporate the October 1, 2010 QRAM Reference Price.

Summary of Gas Cost to Operations
Year ended December 31, 2011

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	1,111,440.1	170,392.3	153.308	4.068
1.3	Western - @ Nova - TCPL	691,069.2	107,643.6	155.764	4.133
1.4	Western Buy/Sell - with Fuel	1,413.9	227.1	160.597	4.261
1.5	Western - @ Alliance	963,416.6	156,391.3	162.330	4.307
1.6	Less TCPL Fuel Requirement	(61,259.4)	0.0		
1.	Total Western Canadian Supplies	2,706,080.4	434,654.4	160.621	4.262
2.	Peaking Supplies	52,410.0	12,150.8	231.842	6.151
3.	Ontario Production	1,460.1	309.1	211.714	5.617
4.	Chicago Supplies	1,846,482.9	341,713.0	185.062	4.910
5.	Delivered Supplies	1,463,916.2	280,583.5	191.666	5.085
6.	Total Supply Costs	6,070,349.6	1,069,410.7	176.170	4.674
	Transportation Costs				
7.1	TCPL - FT - Demand		103,167.4		
7.2	- FT - Commodity	1,742,663.8	4,435.4	2.545	0.068
7.3	- Parkway to CDA		2,282.6		
7.4	- STS - CDA		3,821.1		
7.5	- STS - EDA		3,407.4		
7.6	- Dawn to CDA		6,777.9		
7.7	- Dawn to EDA		16,308.9		
7.8	- Dawn to Iroquois		5,066.9		
7.9	Other Charges		0.0		
7.10	Nova Transmission		4,909.0		
7.11	Alliance Pipeline		41,533.7		
7.12	Vecto Pipeline		26,916.0		
7.	Total Transportation Costs		218,626.4		
8.	Total Before PGVA Adjustment	6,070,349.6	1,288,037.1	212.185	5.630
9.	PGVA Adjustment		(48,530.4)		
10.	Total Purchases & Receipt	6,070,349.6	1,239,506.7	204.190	5.418

Witness: D.Small

Summary of Gas Cost to Operations
Year ended December 31, 2011

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $\$/10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	6,070,349.6	1,239,506.7	204.190	5.418
11.	Storage Fluctuation	(122,245.3)	(24,961.3)		
12.	Commodity Cost to Operations	5,948,104.4	1,214,545.4	204.190	
13.	Storage and Transportation Costs		114,311.1		
14.	Gas Cost to Operations	5,948,104.4	1,328,856.5	223.408	5.928
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		87,432.7		
17.	Forecasted Gas Costs	5,948,104.4	1,416,289.2	238.108	6.318
	Regulatory Adjustments				
18.	NGV Vehicles		0.0		
19.	LRAM Adjustment		0.0		
20.	Accounting Adjustments		0.0		
21.	Forecasted Utility Gas Costs	5,948,104.4	1,416,289.2	238.108	6.318

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2011

Item #		
1.	Sendout To Operations	5,948,104.4
2.	T-Service Volumes	5,423,645.3
3.	Total Sendout	11,371,749.6
4.1	Residential Sales	3,356,349.2
4.2	Commercial Sales	2,007,072.9
4.3	Industrial Sales	366,841.2
4.4	T-Service	5,388,736.4
4.5	Rate 200 T-Service (Gazifere)	33,688.6
4.6	Rate 200 Sales (Gazifere)	123,704.1
4.7	Company Use	5,677.4
4.8	Unaccounted For (UAF)	64,211.4
4.9	Unbilled Forecast - Sales	484.7
4.10	Unbilled Forecast - T-Service	1,220.2
4.11	Lost and Unaccounted For (LUF)	23,763.5
4.12	LUF Capitalized	0.0
4.	Total System Requirements	11,371,749.7

Witness: D.Small

Summary of Storage & Transportion Costs
Fiscal 2011

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2011	Col. 2 Fiscal 2011 Storage Charges Recovered in Fiscal 2011	Col. 3 Fiscal 2010 Storage Charges Recovered in Fiscal 2011	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2011
	Storage				
1.1	Chatham D	132.3	72.7	61.3	134.0
1.2	Injection	121.3	37.2	74.1	111.2
1.3	Withdrawal	107.6	107.6	0.0	107.6
1.4	Cost of Service Storage	0.0	0.0	0.0	0.0
1.5	Market Based Storage	22,971.8	12,615.8	10,633.4	23,249.2
1.6	Other	1,304.5	1,304.5	(39.6)	1,264.9
1.	Total Storage	24,637.5	14,137.8	10,729.2	24,867.0
	Transportation				
2.	Total Transportation	66,454.5	36,495.9	30,813.9	67,309.8
	Dehydration				
3.1	Demand	989.2	543.2	457.7	1,001.0
3.2	Commodity	188.0	188.0	0.0	188.0
3.	Total Dehydration	1,177.2	731.2	457.7	1,189.0
4.	Total Storage & Other Costs	92,269.2	51,364.9	42,000.8	93,365.7
	Fuel Costs				
5.1	Tecumseh	3,353.7	2,171.5	935.9	3,107.4
5.2	Union Storage	1,352.7	895.5	401.1	1,296.6
5.3	Union Transportation	16,642.4	16,074.5	466.9	16,541.4
5.	Total Fuel Costs	21,348.7	19,141.5	1,803.8	20,945.4
6.	Total Storage & Transportation	113,617.9	70,506.4	43,804.6	114,311.1
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				114,311.1

Witness: D.Small

2011
Gas in Storage
Month End Balances and
Average of Monthly Averages

Item #		10^3 m^3	Value ($000)
Month end balances except @ January 1			
1.	January 1	1,407,809.4	388,518.5
2.	January	959,375.2	268,594.4
3.	February	561,052.7	160,142.5
4.	March	320,507.8	96,334.5
5.	April	292,008.6	96,972.0
6.	May	519,181.8	153,612.5
7.	June	857,461.4	234,471.7
8.	July	1,237,394.8	324,397.9
9.	August	1,618,453.2	414,634.1
10.	September	1,963,714.9	496,785.7
11.	October	2,130,349.2	539,762.5
12.	November	1,967,321.3	503,017.9
13.	December	1,530,054.8	391,439.4
14.		1,157,979.4	306,558.7

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	70,525.7	145.650	3.864
1.3	Western - @ Nova - TCPL	768,381.9	113,678.8	147.946	3.925
1.4	Western Buy/Sell - with Fuel	2,072.4	320.7	154.726	4.105
1.5	Western - @ Alliance	968,895.5	161,279.4	166.457	4.416
1.6	Less TCPL Fuel Requirement	(47,911.2)	0.0		
1.	Total Western Canadian Supplies	2,175,651.9	345,804.5	158.943	4.217
2.	Peaking Supplies	26,740.0	9,191.7	343.745	9.120
3.	Ontario Production	1,460.1	298.6	204.475	5.425
4.	Chicago Supplies	2,198,415.3	387,796.7	176.398	4.680
5.	Delivered Supplies	1,071,636.5	199,263.2	185.943	4.933
6.	Total Supply Costs	5,473,903.7	942,354.7	172.154	4.568
	Transportation Costs				
7.1	TCPL - FT - Demand		70,957.3		
7.2	- FT - Commodity	1,206,756.4	3,071.4	2.545	0.068
7.3	- Parkway to CDA		0.0		
7.4	- STS - CDA		4,011.4		
7.5	- STS - EDA		2,996.7		
7.6	- Dawn to CDA		10,173.1		
7.7	- Dawn to EDA		16,308.9		
7.8	- Dawn to Iroquois		0.0		
7.9	Other Charges		0.0		
7.10	Nova Transmission		2,501.0		
7.11	Alliance Pipeline		40,429.2		
7.12	Vecto Pipeline		28,604.1		
7.	Total Transportation Costs		179,053.1		
8.	Total Before PGVA Adjustment	5,473,903.7	1,121,407.8	204.864	5.436
9.	PGVA Adjustment		0.0		
10.	Total Purchases & Receipt	5,473,903.7	1,121,407.8	204.864	5.436

Witness: D.Small

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	1,121,407.8	204.864	5.436
11.	Storage Fluctuation	(79,104.5)	(16,205.7)		
12.	Commodity Cost to Operations	5,394,799.2	1,105,202.1	204.864	
13.	Storage and Transportation Costs		110,171.4		
14.	Gas Cost to Operations	5,394,799.2	1,215,373.5	225.286	5.977
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		87,955.1		
17.	Forecasted Gas Costs	5,394,799.2	1,303,328.6	241.590	6.410
	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	1,303,328.6	241.590	6.410

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 & Transportion 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	Injection	85.4	24.3	87.6	111.9
1.3	Withdrawal	75.5	75.5	-	75.5
1.4	Cost of Service Storage	353.8	189.8	845.1	1,034.9
1.5	Market Based Storage	22,748.6	12,205.7	7,712.8	19,918.5
1.6	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 Storage & Other Costs	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

Witness: D.Small

2010
Gas in Storage
Month End Balances and
Average of Monthly Averages

Item #		Rate Base 10^3 m^3
Month end balances except @ January 1		
1.	January 1	1,615,596.3
2.	January	1,231,237.5
3.	February	900,127.1
4.	March	644,737.6
5.	April	683,364.8
6.	May	851,799.9
7.	June	1,118,055.0
8.	July	1,428,158.3
9.	August	1,763,790.0
10.	September	2,098,794.5
11.	October	2,295,181.1
12.	November	2,131,879.5
13.	December	1,694,700.9
14.		1,400,189.5

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

			Col. 1	Col. 2	Col. 3	Col. 4
			Actual at August 31, 2010		Forecast at December 31, 2010	
Line No.	Account Description	Account Acronym	Principal	Interest	Principal	Interest
			($000's)	($000's)	($000's)	($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2010 DSMVA	(6,443.9)	(13.8)	(1,250.0)	(28.8)
2.	Demand Side Management V/A	2009 DSMVA	1,165.1	-	1,165.1	4.5
3.	Demand Side Management V/A	2008 DSMVA	(73.3)	(56.3)	(73.3)	(56.5)
4.	Lost Revenue Adjustment Mechanism	2009 LRAM	-	-	(45.7)	-
5.	Lost Revenue Adjustment Mechanism	2008 LRAM	37.3	0.2	37.3	0.3
6.	Shared Savings Mechanism V/A	2009 SSMVA	-	-	5,364.2	-
7.	Shared Savings Mechanism V/A	2008 SSMVA	5,803.2	24.6	5,803.2	46.3
8.	Class Action Suit D/A	2010 CASDA	14,128.6	1,174.7	14,128.6	1,227.5 [1]
9.	Deferred Rebate Account	2010 DRA	2,169.9	4.6	2,169.9	12.8
10.	Deferred Rebate Account	2009 DRA	2.7	-	2.7	-
11.	Gas Distribution Access Rule Costs D/A	2010 GDARCDA	88.1	0.2	136.1	0.6 [2]
12.	Gas Distribution Access Rule Costs D/A	2009 GDARCDA	188.7	1.4	188.7	2.1 [2]
13.	Ontario Hearing Costs V/A	2009 OHCVA	19.1	0.1	19.1	0.1
14.	Manufactured Gas Plant D/A	2010 MGPDA	248.5	11.5	373.5	12.6
15.	Unbundled Rate Implementation Cost D/A	2010 URICDA	44.0	-	90.0	0.3
16.	Open Bill Service D/A	2009/10 OBSDA	464.5	17.5	438.5	19.1
17.	Open Bill Access V/A	2009/10 OBAVA	423.1	7.3	397.2	8.8
18.	Municipal Permit Fees D/A	2010 MPFDA	-	-	1,000.0	- [2]
19.	Municipal Permit Fees D/A	2009 MPFDA	916.1	-	916.1	- [2]
20.	Average Use True-Up V/A	2009 AUTUVA	5,626.9	23.8	5,626.9	44.8
21.	Tax Rate and Rule Change V/A	2010 TRRCVA	-	-	970.0	-
22.	Tax Rate and Rule Change V/A	2009 TRRCVA	(350.0)	(1.5)	(350.0)	(3.0)
23.	Earnings Sharing Mechanism D/A	2009 ESMDA	(19,300.0)	(80.0)	(19,300.0)	(152.2)
24.	Mean Daily Volume Mechanism D/A	2010 MDVMDA	-	-	1,640.0	- [2]
25.	IFRS Transition Costs D/A	2010 IFRSTCDA	1,733.4	3.5	1,733.4	9.9
26.	IFRS Transition Costs D/A	2009 IFRSTCDA	2,091.0	8.9	2,091.0	16.8
27.	Ex-Franchise Third Party Billing Services D/A	2010 EFTPBSDA	-	-	(162.7)	-
28.	Ex-Franchise Third Party Billing Services D/A	2009 EFTPBSDA	(27.9)	(0.1)	(27.9)	(0.1)
29.	Total non commodity related accounts		8,955.1	1,126.6	23,081.9	1,165.9
	Commodity Related Accounts					
30.	Purchased Gas V/A	2010 PGVA	(75,405.4)	(89.5)	-	- [3]
31.	Purchased Gas V/A	2009 PGVA	(45,275.2)	(2,521.0)	(45,275.2)	(2,690.5)
32.	Transactional Services D/A	2010 TSDA	(630.2)	-	(2,972.9)	(5.3)
33.	Transactional Services D/A	2009 TSDA	(7,062.1)	(33.0)	(7,062.1)	(59.5)
34.	Unaccounted for Gas V/A	2009 UAFVA	9,596.7	40.6	9,596.7	76.5
35.	Storage and Transportation D/A	2010 S&TDA	36.7	-	36.7	-
36.	Storage and Transportation D/A	2009 S&TDA	(1,594.8)	(9.9)	(1,594.8)	(15.9)
37.	Total commodity related accounts		(120,334.3)	(2,612.8)	(47,271.6)	(2,694.7)
38.	Total Deferral and Variance Accounts		(111,379.2)	(1,486.2)	(24,189.7)	(1,528.8)

Notes:

1. This is the projected CASDA balance at the end of 2010. In EB-2007-0731 the Board approved the clearance of the CASDA over 5 years. The first instalment occurred in 2008. The second, or 2009, instalment was approved by the Board in EB-2009-0055 and was cleared in April and May 2010. The December 2010 balance therefore represents approximately three fifths of the total approved for clearance.

2. The balances in the 2009/10 GDARCDA and MPFDA accounts, as well as the 2010 MDVMDA, are annual expenditures (capital and O&M). Due to the capital component of these expenditures, the company has or will request the clearance of associated annual revenue requirements.

3. As a result of the adoption of the PGVA disposition methodology approved in the EB-2008-0106 proceeding, a projected December 31st balance is no longer required or meaningful.

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

Line No.	Account Description	Account Acronym	Col. 1 Accounts approved in EB-2010-0042 for clearance in January 2011 Principal ($000's)	Col. 2 Interest ($000's)	Col. 3 Current estimate of accounts to be cleared commencing July 1, 2011 Principal ($000's)	Col. 4 Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2010 DSMVA	-	-	-	-
2.	Demand Side Management V/A	2009 DSMVA	-	-	1,165.1	11.7
3.	Demand Side Management V/A	2008 DSMVA	(73.3)	(56.5)	-	-
4.	Lost Revenue Adjustment Mechanism	2009 LRAM	-	-	(45.7)	(0.3)
5.	Lost Revenue Adjustment Mechanism	2008 LRAM	37.3	0.3	-	-
6.	Shared Savings Mechanism V/A	2009 SSMVA	-	-	5,364.2	32.4
7.	Shared Savings Mechanism V/A	2008 SSMVA	5,803.2	46.3	-	-
8.	Class Action Suit D/A	2010 CASDA	4,709.5	450.0 [1]	4,709.5	450.0 [1]
9.	Deferred Rebate Account	2010 DRA	-	-	2,169.9	26.0
10.	Deferred Rebate Account	2009 DRA	-	-	-	-
11.	Gas Distribution Access Rule Costs D/A	2010 GDARCDA	-	-	-	- [2]
12.	Gas Distribution Access Rule Costs D/A	2009 GDARCDA	2,838.8	- [3]	-	-
13.	Ontario Hearing Costs V/A	2009 OHCVA	19.1	0.1	-	-
14.	Manufactured Gas Plant D/A	2010 MGPDA	-	-	-	-
15.	Unbundled Rate Implementation Cost D/A	2010 URICDA	-	-	90.0	0.9
16.	Open Bill Service D/A	2009/10 OBSDA	87.7	3.0	87.7	3.0
17.	Open Bill Access V/A	2009/10 OBAVA	79.5	1.2	79.5	1.2
18.	Municipal Permit Fees D/A	2010 MPFDA	-	-	-	- [2]
19.	Municipal Permit Fees D/A	2009 MPFDA	202.2	- [3]	-	-
20.	Average Use True-Up V/A	2009 AUTUVA	5,626.9	44.8	-	-
21.	Tax Rate and Rule Change V/A	2010 TRRCVA	-	-	970.0	6.0
22.	Tax Rate and Rule Change V/A	2009 TRRCVA	(350.0)	(3.0)	-	-
23.	Earnings Sharing Mechanism D/A	2009 ESMDA	(19,300.0)	(152.2)	-	-
24.	Mean Daily Volume Mechanism D/A	2010 MDVMDA	-	-	-	- [2]
25.	IFRS Transition Costs D/A	2010 IFRSTCDA	-	-	1,733.4	20.1
26.	IFRS Transition Costs D/A	2009 IFRSTCDA	2,091.0	16.8	-	-
27.	Ex-Franchise Third Party Billing Services D/A	2010 EFTPBSDA	-	-	(162.7)	(1.2)
28.	Ex-Franchise Third Party Billing Services D/A	2009 EFTPBSDA	(27.9)	(0.1)	-	-
29.	Total non commodity related accounts		1,744.0	350.7	16,160.9	549.8
	Commodity Related Accounts					
30.	Purchased Gas V/A	2010 PGVA	-	-	-	- [4]
31.	Purchased Gas V/A	2009 PGVA	(45,275.2)	(2,690.5)	-	-
32.	Transactional Services D/A	2010 TSDA	-	-	(2,972.9)	(23.3)
33.	Transactional Services D/A	2009 TSDA	(7,062.1)	(59.5)	-	-
34.	Unaccounted for Gas V/A	2009 UAFVA	9,596.7	76.5	-	-
35.	Storage and Transportation D/A	2010 S&TDA	-	-	36.7	0.3
36.	Storage and Transportation D/A	2009 S&TDA	(1,594.8)	(15.9)	-	-
37.	Total commodity related accounts		(44,335.4)	(2,689.4)	(2,936.2)	(23.0)
38.	Total Deferral and Variance Accounts		(42,591.4)	(2,338.7)	13,224.7	526.8

Notes:

1. The balances shown in the 2010 CASDA account represent the third (2010) and fourth (2011) installments of the balance approved for recovery over five years (2008-2012) in EB-2007-0731. The third (2010) installment was approved for clearance in January 2011 along with other 2009 deferral accounts. EGD is requesting clearance of the 2011 related installment commencing in July 2011.

2. The amounts which will be requested for clearance in relation to the 2010 GDARCDA, 2010 MPFDA, and 2010 MDVMDA will be determined within a revenue requirement calculation as referenced on page 1 of this exhibit. EGD will bring these amounts forward within the presentation of deferral and variance accounts within the 2010 ESM review application and proceeding.

3. The balances in the 2009 GDARCDA and MPFDA accounts are the revenue requirements approved for clearance in the EB-2010-0042 proceeding.

4. The PGVA is now cleared through a rolling twelve month forward looking mechanism as approved by the Board within the EB-2008-0106 proceeding. As such, any 2010 or beyond projected PGVA balances are not meaningful to this schedule.

C – OTHER ITEMS REQUIRING SPECIFIC APPROVAL

DEFERRAL AND VARIANCE ACCOUNTS

A) EB-2010-0042 Clearance of Approved Deferral and Variance Accounts

1. In the decision for the EB-2010-0042 proceeding, the Board approved the clearance of certain Deferral and Variance Accounts ("DA" and "VA") to occur at January 1, 2010. The following is the list of accounts approved for clearance, with the exception of the 2009 Earnings Sharing Mechanism Deferral Account ("ESMDA"), which could possibly be impacted by an outstanding issue within the EB-2010-0042 proceeding, which is still awaiting a Board Decision:

Gas related DA's and VA's:

1. 2009 Purchased Gas VA ("PGVA"),
2. 2009 Transactional Services DA ("TSDA"),
3. 2009 Unaccounted for Gas VA ("UAFVA"), and
4. 2009 Storage and Transportation ("S&TDA").

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

5. 2010 Class Action Suit DA ("CASDA"),
6. 2009 Deferred Rebate Account ("DRA"),
7. 2009 Gas Distribution Access Rule Costs DA ("GDARCDA")
8. 2009 Ontario Hearing Costs VA ("OHCVA"),
9. 2009 Open Bill Service DA ("OBSDA"),
10. 2009 Open Bill Access VA ("OBAVA"),
11. 2009 Municipal Permit Fees DA ("MPFDA"),
12. 2009 Average Use True-Up VA ("AUTUVA"),
13. 2009 Tax Rate and Rule Change VA ("TRRCVA"),
14. 2009 Earnings Sharing Mechanism DA ("ESMDA"),

Witnesses: K. Culbert
A. Kacicnik
D. Small

15. 2009 IFRS Transition Costs DA (“IFRSTCDA”),
16. 2009 Ex-Franchise Third Party Billing Services DA (“EFTPBSDA”)

DSM related DA’s and VA’s:

17. 2008 Demand-Side Management VA (“DSMVA”),
18. 2008 Lost Revenue Adjustment Mechanism (“LRAM”), and
19. 2008 Shared Savings Mechanism VA (“SSMVA”).

B) <u>Outstanding 2009 and 2010 Test Year Approved Deferral and Variance Accounts</u>

4. The following list represents approved and outstanding 2009 variance accounts and the 2010 deferral and variance accounts approved by the Board for continuation or establishment in the 2010 fiscal year for Enbridge, 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”), and
4. 2010 Storage and Transportation (“S&TDA”), and
5. 2010 Change in Purchased Gas Variance Disposition Methodology Deferral Account (“CPGVDMDA”),

Non-Gas related DA’s and VA’s:

6. 2010 Carbon Dioxide Offset Credits DA (“CDOCDA”),
7. 2011 Class Action Suit DA (“CASDA”),
8. 2010 Deferred Rebate Account (“DRA”),
9. 2010 Electric Program Earnings Sharing DA (“EPESDA”),

Witnesses: K. Culbert
A. Kacicnik
D. Small

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 Deferral Account (“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”), and
24. 2010 Mean Daily Volume Mechanism Deferral Account (“MDVMDA”)

DSM related DA’s and VA’s:

25. 2009 Demand-Side Management VA (“DSMVA”),
26. 2009 Lost Revenue Adjustment Mechanism (“LRAM”),
27. 2009 Shared Saving Mechanism VA (“SSMVA”),
28. 2010 Demand-Side Management VA (“DSMVA”),
29. 2010 Lost Revenue Adjustment Mechanism (“LRAM”), and
30. 2010 Shared Saving Mechanism VA (“SSMVA”).

Witnesses: K. Culbert
A. Kacicnik
D. Small

C) Clearance of Deferral and Variance Accounts July 1, 2011

5. The establishment of the above 2009 & 2010 related DA's and VA's was approved by the Board in various earlier proceedings. Within the list of the above accounts, the Board has already approved the clearance of a certain amount in the 2010 CASDA. The 2009 DSMVA, LRAM and SSMVA and related amounts, which are awaiting Board approval, which is anticipated by the end of 2010, will permit their clearance at July, 2011 or potentially at January, 2011 with other accounts approved for clearance at that time.

6. Of the remaining accounts, not all are currently being requested for clearance:
   - The balance in the 2010 Manufactured Gas Plant DA ("MGPDA") will be transferred into a 2011 MGPDA in order to bring forward the accumulated balance in the 2010 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, 2011.
   - 2010 Demand-Side Management VA ("DSMVA"),
   - 2010 Lost Revenue Adjustment Mechanism ("LRAM"),
   - 2010 Shared Savings Mechanism VA ("SSMVA").

7. Due to changes implemented by the Provincial government with respect to the determination of taxable capital and related provincial capital taxes, Enbridge will be recording amounts for 2009 and 2010 within a 2010 Tax Rate and Rule Change

Variance Account ("TRRCVA") which result in a debit to ratepayers. The Company has filed evidence explaining the required and proposed treatment of this element (Exhibit C, Tab 1, Schedule 2). In addition, as per the 2010 EB-2010-0042 agreement, EGD agreed to perform an analysis of any impact of the implementation of the new Harmonized Sales Tax ("HST") on July 1, 2010. As per the agreement, EGD is to record the result of the analysis in the 2010 TRRCVA and bring it forward for review in the spring of 2011 along with all other 2010 deferral and variance accounts requiring review. The Company anticipates a request for clearance of the account commencing July 1, 2011.

8. 2010 Class Action Suit Deferral Account Treatment

- The Class Action Suit deferral account ("CASDA") was approved in 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 like-named deferral account for the next year, until completion of the clearance process. Therefore, in July 2011 the Company will clear approximately one third of the remaining uncleared balance in the CASDA.

9. Open Bill Service DA and Open Bill Access VA Treatment

- The treatment of the recovery of the existing Open Bill Service DA and Open Bill Access VA was approved in 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 like-named account for the next year, until completion of the clearance process. Therefore as the first year of clearance commenced in April, 2010, in July

2011 the Company will clear approximately one half of the remaining balance in the 2010 OBSDA and 2010 OBAVA.

10. A summary of the actual DA and VA balances planned to be cleared commencing July 1, 2011, is included at Exhibit B, Tab 5, Schedule 1, pages 1 and 2.

11. The balances accumulated at the end of December, 2010 and approved to be cleared commencing July 1, 2011, will be included within the Company's July 1, 2011 QRAM filing.

D) <u>Proposed 2011 Deferral and Variance Accounts</u>

12. The Company has reviewed the existing, and potential requirement for, deferral or variance accounts during the IR period and the following is the current list proposed by the Company for the 2011 fiscal year, divided into three groupings - Gas related, Non-Gas related, and DSM related:

Gas related DA's and VA's

1. 2011 Purchased Gas VA ("PGVA"),
2. 2011 Transactional Services DA ("TSDA"),
3. 2011 Unaccounted for Gas VA ("UAFVA"),
4. 2011 Storage and Transportation DA ("S&TDA"), and

Non-Gas related DA's and VA's

5. 2011 Carbon Dioxide Offset Credits DA ("CDOCDA"),
6. 2011 Class Action Suit DA ("CASDA"),
7. 2011 Deferred Rebate Account ("DRA"),
8. 2011 Electric Program Earnings Sharing DA ("EPESDA"),

Witnesses: K. Culbert
A. Kacicnik
D. Small

9. 2011 Gas Distribution Access Rule Costs DA (“GDARCDA”),
10. 2011 Manufactured Gas Plant DA (“MGPDA”),
11. 2011 Municipal Permit Fees DA (“MPFDA”),
12. 2011 Ontario Hearing Costs VA (“OHCVA”),
13. 2011 Unbundled Rate Implementation Cost DA (“URICDA”),
14. 2011 Unbundled Rates Customer Migration VA (“URCMVA”),
15. 2011 Average Use True-Up VA (“AUTUVA”),
16. 2011 Tax Rate and Rule Change VA (“TRRCVA)
17. 2011 Earnings Sharing Mechanism DA (“ESMDA”),
18. 2010 International Financial Reporting Standards Transition Costs Deferral Account (“IFRSTCDA”)
19. 2011 Open Bill Service DA (“OBSDA”),
20. 2011 Open Bill Access VA (“OBAVA”)
21. 2011 Open Bill Revenue VA (“OBRVA”)
22. 2011 Ex-Franchise Third Party Billing Services DA (“ETPBSDA”),
23. 2011 Mean Daily Volume Mechanism DA (“MDVMDA”),

DSM related DA’s and VA’s

24. 2011 Demand-Side Management VA (“DSMVA”),
25. 2011 Lost Revenue Adjustment Mechanism (“LRAM”), and
26. 2011 Shared Savings Mechanism VA (“SSMVA”).

13. All 2011 deferral and variance accounts which continue over from their approval in 2010 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.

Witnesses: K. Culbert
A. Kacicnik
D. Small

D) New Deferral Accounts

14. At this time, Enbridge is not requesting any new deferral accounts for 2011. However, as a result of the potential implication of changes in pension plan regulations, Enbridge has been advised by the actuary for its registered pension plan that there is a possibility of a material pension funding requirement, estimated to be in a range between nil and $20 million, in respect of Enbridge's pension plan in the 2011 fiscal year. At this time, Enbridge cannot be certain that the changes to pension plan regulations will result in a funding requirement in 2011. Pending further information about the potential funding requirement, Enbridge is alerting the Board and parties to this proceeding that should funding for 2011 become necessary, the Company will bring forward a request for appropriate treatment as soon as possible.

UPDATE OF SHARING OF TAX CHANGE FORECAST AMOUNTS

1. Table 1, on page 4, of this exhibit has been prepared and filed in accordance with Enbridge'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 the impact of 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, identified at the time as Appendix A, were the level of forecast and agreed upon tax changes and related amounts to be shared. The agreement recognized that updates of the impact of tax rate and rule changes would occur throughout the IR term, and that changes would be handled through the Tax Rate and Rule Change Variance Account ("TRRCVA") and/or adjustments to annual rates where possible.

4. During Enbridge's 2010, EB-2009-0172 rate proceeding, an updated tax change sharing schedule was filed, reviewed, and approved by the Board. The update was due to changes in rules or rates which occurred subsequent to the changes that were anticipated and embodied within the EB-2007-0615 Rate Order tax sharing calculation.

5. In addition to the changes which were approved during the 2010 proceeding, additional changes have occurred with respect to the rules governing the calculation of Ontario provincial capital taxes. Essentially, effective for 2009 and 2010, the determination of the taxable capital base, which formerly allowed a reduction for the difference between the year-end net book value of assets and the

undepreciated tax value of those assets, was eliminated. The impact of the change, as shown on Table 1, page 4, Line 50, results in an increase of $645.9 million to the tax sharing agreements previously anticipated taxable capital. This change was not anticipated within the original approved or previously updated tax sharing calculations.

6. The impact of the change, which as a result of the timing of tax changes and rates already being established for 2009 and 2010, was not adjusted within rates in those years. The change also does not impact the previously anticipated tax sharing adjustment to 2011 rates as capital taxes are to be eliminated in 2011, as already anticipated in the tax sharing agreement.

7. The change in capital tax determination was not included within Enbridge's 2009 tax provision. Enbridge will be recording the true up within its 2010 financial statements and is not proposing a change to the 2009 TRRCVA but rather, that the impacts be treated within the 2010 TRRCVA as per the provisions of the tax sharing agreement. The treatment within the 2010 Earnings Sharing Mechanism ("ESM") determination will also be appropriately accommodated and explained at the time of the 2010 ESM application.

8. The updated cumulative annual shared tax savings amounts resulting from this change are shown in Table 1 at Line 57, Columns 2 through 5 on page 4. The updated shared tax savings previously approved within Enbridge's 2010 rate application are shown in Table 1 at Line 58 on page 4 and in Table 2, Line 50 on page 5, which is a copy of EB-2009-0172, Exhibit C, Tab 1, Schedule 4. This update changes the annual shared tax savings amounts in the years 2009 and 2010.

9. The impact relating to 2009 is that the previously updated annual forecast tax savings, in the amount of $9.60 million (Table 1, Line 58, Col. 2, p. 4), now

becomes $8.87 million (Table 1, Line 57, Col. 2, p. 4). The decrease of $0.73 million (Table 1, Line 59, Col. 2, p. 4) will be debited to the 2010 TRRCVA.

10. The impact relating to 2010 is that the previously updated annual forecast tax savings, in the amount of $15.80 million (Table 1, Line 58, Col. 3, p. 4), now becomes $15.56 million (Table 1, Line 57, Col. 3, p. 4). The decrease of $0.24 million (Table 1, Line 60, Col. 3, p. 4) will also be debited to the 2010 TRRCVA resulting in a total of $0.97 million of ratepayer share of the capital tax change.

11. As previously indicated, as the elimination of the provincial capital tax in 2011 shown within the original, previously updated and current updated tax sharing calculations is still anticipated, the incremental ratepayer tax savings amounts for 2011 and 2012 remain unchanged and will be incorporated into ongoing rates as shown at Table 1, Lines 61 and 62 of Columns 4 and 5 respectively, on page 4 of this exhibit.

12. Within the 2010, EB-2009-0172 Settlement Agreement, parties agreed that Enbridge would perform an analysis of the impacts of the July 1, 2010 transition to a Harmonized Sales Tax ("HST") and any tax sharing implications. Enbridge was to analyze and record any impact in the 2010 TRRCVA to be brought forward for review in 2011. Enbridge is currently still analyzing any HST impact and will bring forward its finding for review within the application in 2011 for the review of the 2010 approved deferral and variance accounts.

Table 1

2011, Updated Summary - Sharing of Tax Change Forecast Amounts

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

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

Table 2

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 **2008**	Col. 2 **2009**	Col. 3 **2010**	Col. 4 **2011**	Col. 5 **2012**	Col. 6
	Tax Related Amounts Forecast from CCA Rate Changes **($ Millions)**						
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45/50) - Opening UCC Balance	1.54	2.24	1.14	0.51	1.64	
6.	New purchases (2007 Board Approved additions) -**with update for new Class 52**	2.13	2.13	2.13	2.13	2.13	
7.	**Re-grouping of amounts eligible for Class 52 (included at line 11)**	-	(1.95)	(2.13)	(0.18)	-	
8.	Capital Cost Allowance (CCA) at 55% -2007 Federal Budget tax rule CCA rate	1.43	1.28	0.63	0.82	1.49	
9.	Closing Undepreciated Capital Cost (UCC)	2.24	1.14	0.51	1.64	2.28	
10.	Computer Equipment (**New Class 52**) - Opening UCC Balance	-	-	-	-	-	
11.	New purchases (2007 Board Approved additions) -**with update for new Class 52**	-	1.95	2.13	0.18	-	
12.	Capital Cost Allowance (CCA) at 100% -2007 Federal Budget tax rule CCA rate	-	1.95	2.13	0.18	-	
13.	Closing Undepreciated Capital Cost (UCC)	-	-	-	-	-	
14.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.76	687.71	898.86	1101.57	
15.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
16.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
17.	Closing Undepreciated Capital Cost (UCC)	467.76	687.71	898.86	1101.57	1296.16	
18.	Distribution Assets (Class 51) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
19.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
20.	Capital Cost Allowance (CCA) at 6% -2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
21.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
22.	CCA Difference	7.27	12.82	15.85	17.29	20.67	
23.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	31.00%	28.25%	26.25%	
24.	Tax Impact	2.44	4.23	4.91	4.89	5.43	
25.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.65	6.31	7.12	6.81	7.36	31.26
26.	Incremental Amount	3.65	2.66	0.81	(0.31)	0.55	
27.	**50% of the Amount to Reduce Rates**	**$1.83**	**$1.33**	**$0.40**	**-$0.16**	**$0.28**	
	Tax Related Amounts Forecast from Income Tax Rate Changes						
28.	Taxable Income (2007 Board Approved, Final Rate Order, App.A, S3,P3,L15)	355.6	355.6	355.6	355.6	355.6	
29.	Gross Deficiency (2007 Board Approved, Final Rate Order, App.A, S1,P1,L7)	42.7	42.7	42.7	42.7	42.7	
30.	Interest Expense (2007 Board Approved, Final Rate Order, App.A, S3,P3,L25)	(165.90)	(165.90)	(165.90)	(165.90)	(165.90)	
31.	Board Approved Taxable Income for Income Tax Expense Calculation	232.40	232.40	232.40	232.40	232.40	
32.	2007 Approved Tax Rate (2007 Board Approved, Final Rate Order, App.A, S3,P3,L27)	36.12%	36.12%	36.12%	36.12%	36.12%	
33.	Anticipated Tax Rates During the IR Term	33.50%	33.00%	31.00%	28.25%	26.25%	
34.	Tax Rate Variance	2.62%	3.12%	5.12%	7.87%	9.87%	
35.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	11.90	18.29	22.94	
36.	Grossed-up Tax Savings	9.16	10.82	17.25	25.49	31.11	93.83
37.	Incremental Amount	9.16	1.66	6.43	8.24	5.62	
38.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$3.22**	**$4.12**	**$2.80**	
	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	

2009 HISTORICAL RESULTS AND ASSOCIATED INFORMATION

1. The Company's Fiscal 2009 Historical Utility financial results and supporting customer, volumetric, revenue and cost information were filed, reviewed and approved by the Board within the 2009 Earnings Sharing Mechanism proceeding, docket number EB-2010-0042.[1]

[1] The stock based compensation issue remains an open item and is before the Board awaiting final Decision.

Witness: K. Culbert

SERVICE QUALITY REQUIREMENTS

1. The purpose of this evidence is to review the filed results for the Service Quality Requirements in 2008 and 2009 and discuss what action has been taken to remediate the identified gaps.

TABLE 1: SQR TARGETS vs ACTUALS

Year	2008	2009
AMWDTP Target	85%	85%
AMWDTP Actual	93.7%	97.4%
ECRWOH Target	90%	90%
ECRWOH Actual	94.2%	96.2%
TRMA Target	100%	100%
TRMA Actual	62.8%	97.6%
NDTRAC Target	85%	85%
NDTRAC Actual	97.7%	94.3%

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]

[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").

3. The performance versus target on TRMA improved from 62.8% in 2008 to 97.6% in 2009. These results represent the number of customers whose appointments were missed that the Company contacted within the 2 hours of the end of the appointment time divided by the total number of missed appointments.

4. During 2009, the Company significantly improved the performance on this metric compared to previous years. This was achieved through work done by a cross functional team. Priorities were to utilize process improvement established in previous years, including meeting the initial appointment, thus reducing the need for rescheduling. All missed appointments have been reviewed to prevent reoccurrence. A refresher training 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 not withstanding challenges resulting from the implementation 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.

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.

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.

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.

TABLE 2: SQR TARGETS vs ACTUALS

Year	2008	2009
CASL Target	75%	75%
CASL Actual	76.0%	74.1%
NCAR Target	10%	10%
NCAR Actual	3.7%	7.0%
MRP Target	0.5%	0.5%
MRP Actual	0.7%	0.5%
NDTPWR Target	80%	80%
NDTPWR Actual	100.0%	100.0%

8. The annual standard for Call Answering Service Level (“CASL”) is 75%. The Company's result for 2009 was 74.1%.

9. Enbridge implemented a new Customer Information System (“CIS”) in September 2009. It was expected that the implementation of the new CIS would have an effect on the CASL, so the Company undertook several additional initiatives to achieve the CASL Targets. Prior to the new CIS going live, Call Centre staff were trained through instructor led classroom sessions and individual tutorial practice sessions. In addition, 180 additional staff were added to the call centre to assist in backfilling staff while in classroom training to not impact service levels during the extensive training period. The same staff were retained to assist

in handling calls post going live in anticipation of increased call handling times as Customer Service Representatives were using the system in the course of handling customer inquiries. To further support Call Centre staff, the trainers were used as on site support on the call centre floor and provided one on one coaching and assisted in the troubleshooting and resolution of system and process issues. The Company also promoted its self service options through the web and email channels. As a result, there was a 60% increase in email and web forms in October 2009 compared to prior years.

10. Although the Company did encounter the inevitable issues once going live, the implementation of the new CIS was a success. The measures taken by the Company to manage the impact in the Call Centre were successful in mitigating the impact on our customers. The Company was back to normal CASL levels in the month of November, within 2 months of implementing the new CIS which was earlier than expected and sooner than most companies implementing a new CIS.

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")

<u>DSM related DA's and VA's</u>

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

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
Row		2008	2009	2010	2011	2012	
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.

Line No.	Summary - Sharing of Tax Change Forecast Amounts	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Tax Related Amounts Forecast from CCA Rate Changes ($ Millions)	**2008**	**2009**	**2010**	**2011**	**2012**	
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	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	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 ITEM NO.	Col. 2 DESCRIPTION	Col. 3 TOTAL	Col. 4 RATE 1	Col. 5 RATE 6	Col. 6 RATE 9	Col. 7 RATE 100	Col. 8 RATE 110	Col. 9 RATE 115	Col. 10 RATE 125	Col. 11 RATE 135	Col. 12 RATE 145	Col. 13 RATE 170	Col. 14 RATE 200	Col. 15 RATE 300 Firm	Col. 16 RATE 300 Int	Col. 17 DIRECT PURCHASE
	Total DRR	1,006.4	673.5	262.2	1.3	27.6	11.2	8.4	6.4	0.7	4.9	5.3	2.3	0.4	0.2	1.6
	Y Factor: Other															
1.1	2011 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2011	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2011	89.2	82.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2011 Leave to Construct	3.0	1.3	1.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	159.5	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	-
	Total DRR minus Y-Factor	846.8	558.1	230.4	1.3	22.6	9.8	6.8	6.3	0.6	3.8	2.8	1.7	0.4	0.2	1.6

Estimated Assignment of 2008-2012 Distribution Revenue (With and Without Y Factors) to Rate Classes

2012

Col. 1 ITEM NO.	Col. 2 DESCRIPTION	Col. 3 TOTAL	Col. 4 RATE 1	Col. 5 RATE 6	Col. 6 RATE 9	Col. 7 RATE 100	Col. 8 RATE 110	Col. 9 RATE 115	Col. 10 RATE 125	Col. 11 RATE 135	Col. 12 RATE 145	Col. 13 RATE 170	Col. 14 RATE 200	Col. 15 RATE 300 Firm	Col. 16 RATE 300 Int	Col. 17 DIRECT PURCHASE
	Total DRR	1,029.1	688.8	268.1	1.3	28.2	11.4	8.6	6.5	0.7	5.0	5.4	2.4	0.4	0.2	1.6
	Y Factor: Other															
1.1	2012 Gas in Storage and Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2012	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2012	89.2	82.0	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2012 Leave to Construct	2.9	1.3	1.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	159.5	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	-
	Total DRR minus Y-Factor	869.6	573.4	236.4	1.3	23.2	10.1	7.0	6.3	0.7	3.9	2.9	1.8	0.4	0.2	1.6

Estimated Rate Impacts (2008-2012)

ESTIMATED 2008-2012 RATE IMPACTS

Rate Class	ADR 2008[1] T-Service Rate Impact	ADR 2009[2] T-Service Rate Impact	ADR 2010[3] T-Service Rate Impact	ADR 2011[4] T-Service Rate Impact	ADR 2012[5] T-Service Rate Impact
1	0.1%	2.1%	1.6%	1.5%	1.7%
6	0.0%	1.8%	1.3%	1.2%	1.4%
9	0.1%	0.8%	1.1%	1.2%	1.6%
100	0.1%	1.3%	1.0%	0.9%	0.9%
110	0.1%	1.1%	1.0%	0.9%	0.9%
115	0.1%	1.1%	0.8%	0.8%	0.8%
135	0.6%	0.9%	0.9%	0.9%	0.9%
145	0.2%	1.0%	0.9%	0.8%	0.8%
170	0.4%	1.0%	0.9%	0.9%	0.9%
200	0.4%	1.0%	0.9%	0.8%	1.0%
	ADR 2008 Distribution Rate Impact	ADR 2009 Distribution Rate Impact	ADR 2010 Distribution Rate Impact	ADR 2011 Distribution Rate Impact	ADR 2012 Distribution Rate Impact
125	0.0%	0.7%	0.7%	0.7%	0.7%
300	0.1%	0.9%	0.9%	0.9%	0.9%

Notes:
1. - 2008 Distribution Revenue Requirement of $935 M
2. - 2009 Distribution Revenue Requirement of $963 M
3. - 2010 Distribution Revenue Requirement of $986 M
4. - 2011 Distribution Revenue Requirement of $1,006 M
5. - 2012 Distribution Revenue Requirement of $1,029 M

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Estimated Bill Impacts (2008-2012)

Sample Typical Customer Estimated T-Service Bill Impacts from 2008 to 2012
As Per Settlement Proposal

	October 1, 2007 T-Service Bill (1) Annual Bill ($)	Estimated 2008 T-Service Bill Annual Bill ($)	Estimated 2008 Annual $ change	Estimated 2009 T-Service Bill Annual $ change	Estimated 2010 T-Service Bill Annual $ change	Estimated 2011 T-Service Bill Annual $ change	Estimated 2012 T-Service Bill Annual $ change	Total 2008-2012 T-Service Bill Cumulative $ change	Cumulative % change
Rate 1									
Rate 1 T-Service Bill Impact	409.37	416.18	6.81	8.68	6.93	6.45	7.58	36.44	8.9%
Note: (1) based on annual consumption of 1,955 m3									
Rate 1 T-Service Bill Impact	558.77	559.89	1.12	11.67	9.32	8.67	10.19	40.98	7.3%
Note: (1) based on annual consumption of 3,064 m3									
Rate 1 T-Service Bill Impact	772.67	755.35	(17.32)	15.75	12.57	11.70	13.75	36.45	4.7%
Note: (1) based on annual consumption of 4,691 m3									
Rate 6									
Rate 6 T-Service Bill Impact	2,879.90	2,882.78	2.88	51.73	39.42	36.71	42.53	173.27	6.0%
Note: (1) based on annual consumption of 22,606 m3									
Rate 6 T-Service Bill Impact	5,023.61	4,710.21	(313.40)	84.52	64.40	59.99	69.50	-34.99	-0.7%
Note: (1) based on annual consumption of 43,285 m3									
Rate 115									
Rate 115 T-Service Bill Impact	3,356,188	3,359,796	3,608	36,958	25,691	25,723	25,969	117,948	3.5%
Note: (1) based on annual consumption of 69,832,850 m3 at 80% Load Factor									

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
BALANCES

Line No.	Account Description	Account Acronym	Col. 1 December 31, 2007 Principal ($000's)	Col. 2 December 31, 2007 Interest ($000's)	
	Non Commodity Related Accounts				
1.	Demand Side Management Account V/A	2007 DSMVA	(616.1)	(95.0)	
2.	Demand Side Management Account V/A	2006 DSMVA	374.7	(21.7)	
3.	Demand Side Management Account V/A	2005 DSMVA	697.5	23.2	
4.	Lost Revenue Adjustment Mechanism	2007 LRAM	-	-	
5.	Lost Revenue Adjustment Mechanism	2006 LRAM	(339.5)	(1.5)	
6.	Lost Revenue Adjustment Mechanism	2005 LRAM	(832.3)	(3.6)	
7.	Shared Savings Mechanism V/A	2007 SSMVA	-	-	
8.	Shared Savings Mechanism V/A	2006 SSMVA	11,229.1	-	
9.	Shared Savings Mechanism V/A	2005 SSMVA	-	-	
10.	Class Action Suit D/A	2007 CASDA	23,545.0	1,165.1	
11.	Deferred Rebate Account	2007 DRA	466.0	4.0	
12.	Debt Redemption D/A	2007 DRDA	(2,575.6)	(27.9)	
13.	Gas Distribution Access Rule Costs D/A	2007 GDARCDA	6,982.6	206.0	
14.	Ontario Hearing Costs V/A	2007 OHCVA	2,555.5	32.6	
15.	Manufactured Gas Plant D/A	2007 MGPDA	80.3	3.3	
16.	Electric Program Earnings Sharing D/A	2007 EPESDA	(308.7)	-	
17.	Corporate Cost Allocation Methodology D/A	2006 CCAMDA	475.2	23.3	
18.	Customer Care V/A	2007 CCVA	1,736.6	-	
19.	Unbundled Rate Implementation Cost D/A	2007 URICDA	199.3	7.6	
20.	Open Bill Service D/A	2007 OBSDA	574.1	46.2	
21.	Open Bill Access V/A	2007 OBAVA	146.8	-	
22.	Total non commodity related accounts		44,390.5	1,361.6	
	Commodity Related Accounts				
23.	Purchased Gas V/A	2007 PGVA	(137,102.5)	(4,060.7)	a)
24.	Transactional Services D/A	2007 TSDA	(8,698.4)	(99.4)	
25.	Unaccounted for Gas V/A	2007 UAFVA	6,112.1	-	
26.	Union Gas D/A	2007 UGDA	3,294.5	64.7	
27.	Total Commodity related accounts		(136,394.3)	(4,095.4)	
28.	Total deferral and variance accounts		(92,003.8)	(2,733.8)	

Notes:

a) PGVA balance is being cleared through Rider "C" treatment and unit rates as approved in the January 1, 2008 QRAM, EB-2007-0897. One time true up amount to be determined and proposed for clearance at time of July 1, 2008 QRAM.

b) Other than PGVA clearance none of the amounts shown have yet received Board Approval for clearance. The Company will file a schedule of balances and proposal for timing of clearances for review and approval by the end of February 2008.

Filed: 2010-10-01
EB-2010-0146
Exhibit E
Tab 2
Schedule 1

Final Rate Order
Filed: 2008-04-02
EB-2007-0615
Appendix F
Page 1 of 1

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") to be used for the calculation of earnings sharing, if any, for the 2011 Historical Year. The /C Earnings Sharing Mechanism ("ESM") application for the 2010 Historical Year is expected to be filed in March, 2011.

2. As a result of the unavailability of underlying information (i.e. the economic forecasts which constitute the October consensus materials), the Company will update this exhibit at some point in the future.

UPDATE

3. Please see Appendix A for the ROE calculations for 2011.

Witnesses: I. McLeod
S. Murray

APPENDIX A: RETURN ON EQUITY CALCULATION FOR 2011

1. The purpose of this appendix is to provide the Return on Equity ("ROE") used for the calculation of earnings sharing, if any, for 2011. The Company has calculated ROE for 2011 using two methodologies. The first methodology in Table A1 is provided in the Board's "Draft Guidelines on a Formula-Based Return on Equity for Regulated Utilities". The second methodology in Table A2 is provided in the "Report of the Board on the Cost of Capital for Ontario's Regulated Utilities".

2. The Company will indicate, within its 2011 earnings sharing application, which methodology it employs for the calculation of 2011 earnings sharing.

3. Table A1 below shows the calculation of ROE for 2011 under the first methodology.

Table A1
Determination of ROE for 2011

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Yield on 10s 3 Months Out[a]	Yield 10s 12 Months Out[a]	Average 10s Yield	Average Spread (30s-10s)[b]	Long Bond Forecast	Difference in Long Bond Forecast	0.75xDifference (Rounded to 2 Decimal Places)	ROE (%)
		(Col. 1+Col. 2)/2		Col. 3+Col. 4	Col. 5-4.23	0.75xCol. 6	8.37+Col. 7
2.80	3.30	3.05	0.60	3.65	-0.58	-0.43	7.94

Notes:
2010 ROE: 8.37
2010 Long Canada Forecast: 4.23
[a] From Consensus Forecasts October 11, 2010
[b] From Financial Post

Based on the October 2010 Consensus Forecasts publication and the data provided in the Financial Post, ROE for 2011 is 7.94%.

4. Table A2 below shows the calculation of ROE for 2011 under the second methodology.

Table A2
Determination of ROE for 2011

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*	*Col. 11*
Yield on 10s 3 Months Out[a]	Yield 10s 12 Months Out[a]	Average 10s Yield	Average Spread (30s-10s)[b]	Long Bond Forecast	Difference in Long Bond Forecast	0.5xDifference in Long Bond Forecast	Yield Spread (Utility Bond Yield[c] - GOC 30s[b])	Difference in Yield Spread	0.5xDifference in Yield Spread	ROE (%)
		(Col. 1+Col. 2)/2		Col. 3+Col. 4	Col. 5-4.25	0.5xCol. 6		Col. 8 - 1.415	0.5xCol. 9	9.75+Col. 7+Col. 10
3.10	3.60	3.35	0.59	3.94	-0.31	-0.15	1.54	0.124	0.060	9.66

Notes:
2010 ROE: 9.75
2010 Long Canada Forecast: 4.25
2010 A-Rated Utility Bond Forecast: 1.415
[a] From Consensus Forecasts September 13, 2010
[b] From Statistics Canada
[c] From Bloomberg L.P.

Based on the September 2010 Consensus Forecasts publication and the data provided by Statistics Canada and Bloomberg L.P., ROE for 2011 is 9.66%.