2009 RATE ADJUSTMENT SUMMARY

1. The Company is proposing to adjust its rates for the 2009 fiscal year within the parameters established in the Board Approved Incentive Regulation ("IR") formula (EB-2007-0615 dated 11-Mar-2008). The Settlement Agreement from that proceeding (filed at Exhibit E-1-1 for reference in this proceeding), included at issue 12.1.1, the dates and filing requirements within which Enbridge would file its rate adjustment evidence. In compliance with that document, Enbridge has filed this, its 2009 Rate Adjustment application.

2. The Company has proposed an approach which is designed to adjust rates to be implemented effective in January 2009 within the time constraints stipulated in its Settlement Agreement from the IR proceeding (filed by October 1 and a Decision by December 15). The Company's proposal has been filed at Exhibit A-3-1.

3. The evidence supporting the mechanical aspects of the proposed 2009 Rate Adjustment have been filed in the "B" series of exhibits. This evidence correlates to the determination of rates in the proposed Phase I portion of this proceeding. The 2009 revenue per customer cap determination is filed at Exhibit B-1-2, the proposed rate schedules are found at Exhibit B-3-2 and the Draft Rate Order – Interim ("DRO-I") is filed at Exhibit B-1-9. The balance of the exhibits represent material that has been filed, as it has in the past, in support of the materials found in the revenue per customer cap exhibit of the development of the rate schedules or DRO-I.

4. The evidence filed in the "C" series of exhibits correlates to the Company's proposed Phase II issues. This material relates to the Company's deferral and variance account treatment including the proposed International Financial Reporting Standards deferral account ("IFRSDA") filed at Exhibit C-1-2, the proposed changes

to certain listed items on Rider G – the schedule of non-energy service charges filed at Exhibit C-1-3, the proposed wording changes to the rate handbook filed at Exhibit C-1-4, the changes to the reporting of Envision benefits at Exhibit C-1-5, a proposal to change the IVA service charge at Exhibit C-1-6 and a proposal to require firm upstream transportation to be contracted for in certain circumstances filed at Exhibit C-1-7.

5. The ADR Settlement Agreement in the 2008 IR proceeding provided that historical year information would be filed as we progress through the IR plan period. As the 2007 Historical Year is not subject to an Earnings Sharing Mechanism, this information is not provided for the purposes of an earnings sharing calculation, but simply to comply with the requirement of the 2008 IR Settlement Agreement regarding provision of historical year information. The 2007 historical year information has been filed in the "D" series of exhibits.

6. The information provided in the "E" series of exhibits has been filed for reference purposes as it represents evidence that has been brought forward from earlier proceedings and filed herein for ease of access. Exhibit E-4-1 will be filed when the underlying forecast information usually referred to as the 'October Consensus Forecast' is available (sometime in late October). This information will provide the Company with the ability to generate the Return on Equity ("ROE") within the parameters of the Board Approved Formula for the establishment of the 2009 Fiscal Year ROE on a forward test year basis as previously established and approved. Once calculated, the 2009 ROE will be provided as a reference for future consideration when the 2009 historical results are known and any potential for earnings sharing with ratepayers is to be determined.

2009 REVENUE PER CUSTOMER CAP, DISTRIBUTION AND
TOTAL REVENUE DETERMINATION

Row		Col. 1 2009
1.	2008 Total Approved Revenue	2,867.0
2.	Gas Costs to operations (at Oct. 1, 2007 ref. price)	1,929.0
3.	2008 Approved Distribution Revenue	938.0
4.	2008 Gas in storage related carrying costs (at Oct. 1, 2007 ref. price)	(43.1)
5.	DSM 2008 amount	(23.1)
6.	CIS / Cust. Care 2008 amount	(92.4)
7.	Power generation projects 2008 amount	0.1
8.	Distribution Revenue Sub-total	779.5
9.	Ratepayer 50% share of 2009 incremental tax amounts	(1.8)
10.	Distribution Revenue base (subject to the escalation formula, $millions)	777.7
11.	Average Number of Customers (Beginning)	1,864,047
12.	Distribution Revenue per Customer 2009 (Beginning)	$ 417.21
13.	GDP IPI FDD	1.54%
14.	Inflation Coefficient (allowed % of GDP IPI FDD)	55.00%
15.	Escalation Factor, 100 plus (GDP IPI FDD multiplied by the inflation coeff.)	100.85%
16.	Distribution Revenue per Customer 2009 (Ending)	$ 420.75
17.	Average Number of Customers (Ending)	1,906,437
18.	Distribution Revenue (resulting from the escalation formula, $millions)	802.14
19.	2009 Gas in storage related carrying costs (at Oct. 1, 2008 ref. price)	50.40
20.	DSM 2009 approved amount	24.30
21.	CIS / Customer Care 2009 approved amount	94.10
22.	Power generation projects 2009 amount	3.20
23.	Total Y-Factors	172.00
24.	Resulting 2009 Distribution Revenues	974.14
25.	2009 Gas Costs to operations (at Oct. 1, 2008 ref. price)	2,389.70
26.	2009 Total Revenue	3,363.84

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

2009 DISTRIBUTION REVENUE PER CUSTOMER CAP
DISTRIBUTION AND TOTAL REVENUE DETERMINATION (2009)

Enbridge's revenue per customer cap calculation for its 2009 rate adjustment, has been determined through the continued use and updating of various components or elements of the Incentive Regulation model and revenue determination formula which was approved by the Board in EGD's 2008 rate proceeding, EB-2007-0615.

As shown on page 1 of this schedule, the 2009 total revenue amount to be collected through rates is calculated through the completion of the following process. Formula amounts and percentages referred to below are all found in Column 1 of page 1.

Process

1. Row 1, $2,867.0 million, the starting point of the calculation, is the 2008 Total Board Approved revenue as per the EB-2007-0615 Final Rate Order. (Appendix A, p. 1, Column 1, Line 27)

2. Row 2, eliminates the gas cost of $1,929.0 million embedded within that total approved revenue to arrive at Row 3, the 2008 Board Approved distribution revenue of $938.0 million. Removal of this gas cost is necessary as it was based on prices underpinning the October 1, 2007 gas cost reference price of $323.347 /$10^3 m^3$ and was relative to 2008 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 2009 forecast gas cost, outside of the incentive escalation formula, is included into the 2009 total revenue at Row 25, and is explained later in this evidence.

3. Row 3, shows the 2008 Board Approved distribution revenue of $938.0 million to which the following further adjustments are required in order to calculate a distribution revenue upon which the incentive escalation formula can be applied within the context of EGD's approved revenue per customer cap model.

4. Row 4, eliminates $43.1 million, which is the embedded carrying cost on gas in storage and working cash related to gas costs in the 2008 Board Decision which are eliminated and explained at Row 2 above. Similar to Row 2, this elimination is

[1] That reference price has been replaced within rates throughout each quarter in 2008. Prices underpinning the Oct. 1, 2008 reference price are embedded in the 2009 forecast of gas cost at the time of the 2009 application.

required in order to remove the carrying cost on gas in storage and gas cost working cash embedded in the 2008 Board Approved distribution revenue which was based on 2008 approved volumes and prices underpinning the October 1, 2007 gas cost reference price of $323.347 /$10^3m^3$. This elimination is necessary in order to establish a distribution revenue upon which the incentive escalation formula can be applied exclusive of carrying costs on 2008 gas in storage and gas cost working cash amounts related to 2008 approved volumes and gas cost prices. A carrying cost on gas in storage and gas cost working cash for 2009, outside of the incentive escalation formula, is included in the 2009 total revenue and explained at Row 19 later in this process. (Ref. Exhibit B-1-2, Appendix A)

5. Row 5, removes the 2008 Board Approved DSM operating costs of $23.1 million as established within the EB-2006-0021 Decision. This adjustment is necessary as the 2009 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 2008 approved amounts. The 2009 Board Approved DSM operating costs, outside of the incentive escalation formula, are included into the 2009 total revenue at Row 20.

6. Row 6, removes the 2008 Board Approved CIS/Customer Care costs of $92.4 million (exclusive of bad debt) (shown at Appendix F in the EB-2007-0615 Rate Order). This adjustment is necessary as the base distribution revenue upon which the incentive escalation formula is to be applied should exclude CIS/Customer Care costs. The 2009 Approved CIS/Customer Care costs are included in the 2009 distribution revenue outside of the incentive escalation formula and are further outlined at Row 21.

7. Row 7, removes the 2008 Board Approved power generation related Y-factor revenue requirement amount of $0.1 million from the base subject to escalation. The inclusion of an updated 2009 revenue requirement amount of $3.2 million is shown at Row 22. Power generation project cost treatment was approved to be handled outside of the escalation portion of the incentive formula.

8. Row 8, shows a distribution revenue sub-total of $779.5 million, inclusive of all of the above noted adjustments. This is the exact amount of the Board Approved formula portion of 2008 rates as shown at Appendix A, page 1, Column 1, Row 19 of the EB-2007-0615 Rate Order.

9. Row 9, incorporates an incremental reduction to base rates of $1.8 million, which is the 2009 ratepayer amount relating to incremental tax rate and rule change

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

expectations which were agreed to be shared equally between ratepayers and the Company. At this time, the Company has continued with the rate adjustment which was agreed upon and approved in relation to the anticipated tax rate and rule changes. However, as of the date of this filing, legislation enacting the anticipated Capital Cost Allowance ("CCA") rate changes had not received approval by the Federal Government. If the anticipated CCA rate changes do not receive order in council approval before the end of 2008, the Company will be required to record any variance amount in the Tax Rate and Rule Change Variance Account for the recovery of the 2008 benefit which did not materialize. Further, the Company will need to determine any required adjustment to ongoing rates and or further future variance account treatment, once the CCA rate change issue is resolved. The methodology and the incremental amounts agreed to for 2009 through 2012, are found in the EB-2007-0615 Rate Order, Appendix A, Schedule 1, Summary – Sharing of Tax Change Forecast Amounts.

10. Row 10, shows the total base distribution revenue of $777.7 million, upon which the Approved incentive escalation formula can be applied.

11. Row 11, provides the 2008 Board Approved average number of customers of 1,864,047 (from EB-2007-0615, Rate Order, Appendix A, p. 1, Column 1, Row 18) which is used in the next step of this process to calculate the base distribution revenue/customer exclusive of Y and Z factors.

12. Row 12, is the base distribution revenue per customer of $417.21, which is derived by dividing the Row 10 base distribution revenue of $777.7 million by the 2008 approved average customers of 1,864,047.

13. Row 13, 1.54%, is the updated GDP IPI FDD inflation factor component of the EB-2007-0615 Board Approved incentive escalation formula which is found in evidence at Exhibit B-1-3.

14. Row 14, 55%, is the 2009 inflation co-efficient component of the incentive escalation formula as approved by the Board in the EB-2007-0615 Rate Order, Appendix A, page 1, Column 2, Row 15.

15. Row 15, 100.85% (or a multiplier of 1.0085) is the adjustment factor calculated as, 100% plus 0.85% (0.85% is calculated as the GDP IPI FDD inflation factor of 1.54% multiplied by 55%) which is required in the next step to arrive at an escalated average distribution revenue per customer amount.

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

16. Row 16, $420.75, is the 2009 distribution revenue per customer which is calculated by multiplying the distribution revenue per customer at Row 12 of $417.21 by the adjustment factor of 100.85% or a multiplier of 1.0085.

17. Row 17, provides the 2009 forecast average number of customers of 1,906,437 which is found in evidence at Exhibit B-1-4.

18. Row 18, $802.14 million, is the 2009 distribution revenue which is calculated by multiplying the 2009 distribution revenue per customer amount of $420.75 by the forecast 2009 average number of customers of 1,906,437. This distribution revenue is further adjusted in Rows 19 through 25 to arrive at a 2009 total revenue for which 2009 rates are developed.

19. Row 19, increases the $802.14 distribution revenue by $50.4 million for carrying costs on 2009 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 2008 approved distribution revenue need to be removed from a base in order to apply an incentive escalation formula, the 2009 carrying costs on gas in storage and gas cost working cash related to 2009 forecast volumes and prices underpinning the Oct. 1, 2008 gas cost reference price need to be included in the 2009 total revenue. This type of adjustment is required in order to develop rates which incorporate the upcoming 2009 volumetric forecasts and changes in approved gas prices. (Ref. Exhibit B-1-2, Appendix A)

20. Row 20, increases the $802.14 million distribution revenue by $24.3 million, which is the 2009 Board approved DSM operating costs as established in the EB-2006-0021 Decision. This is required to include a 2009 DSM amount into the 2009 total revenue to replace the previously removed 2008 DSM operating costs as explained in the narrative for Row 5.

21. Row 21, increases the $802.14 million distribution revenue by $94.1 million, the 2009 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, $3.2 million, represents the 2009 revenue requirement associated with Y-factor capital expenditures for power generation projects which the Board approved the inclusion of within EGD's Incentive Regulation formula and determination. Evidence is found at Exhibit B-1-6, Appendix A.

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

23. Row 23, is the sum of Rows 19, 20, 21 & 22.

24. Row 24, $974.14 million, is EGD's total 2009 distribution revenue before gas costs which 2009 rates will be designed to recover.

25. Row 25, $2,389.7 million, is the 2009 forecast gas cost required to be added to the 2009 distribution revenue to establish 2009 total required revenue. The $2,389.7 million replaces the previously removed 2008 gas cost value embedded within the starting 2008 Total Board Approved revenue as explained in the narrative for Row 2. Evidence is found at Exhibit B-5-1.

26. Row 26, $3,363.44 million, is the 2009 total revenue arrived at and to be used to design rates, following the application of the sum of all of the elements of the agreed upon incentive escalation formula. The 2009 rates will be designed to recover this amount based on the forecast of 2009 volumes.

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

2009 Forecast Gas in Storage
In Rate Base and its Associated
Gross Carrying Cost

Line No.		Col.1 Exhibit Reference	Col.2	Col.3
				($000)
		EB-2008-0219	($10^3 m^3$)	
1.	Average gas in storage volume & value	Exhibit B.T5.S2.pg.4, line 14	1 160 383.9	511,235.1
2.	Gas cost working cash allowance			
2.1	a) Purchase cost of gas		$2,380,207.6	
2.2	b) Net lag-days calculated	EB-2008-0263,Q4-3.T2.S2.line 3.2	4.2	
2.3	c) Dollar days		9,996,871.9	
2.4	d) Number of operating days		365	27,388.7
3.	Rate Base value			538,623.8
4.	Gross return component	(See page 3 of this schedule)		9.36%
5.	Carrying cost requirement			50,415.2

2008 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-2007-0615	(10^3m^3)	
1.	Average gas in storage volume & value	Exhibit C.T1.S2.pg.4, line 14	1 207 174.0	439,049.5
2.	Gas cost working cash allowance			
2.1	a) Purchase cost of gas		$1,960,917.2	
2.2	b) Net lag-days calculated	EB-2007-0701,Q4-3.T2.S2.line 3.2	3.9	
2.3	c) Dollar days		7,647,577.1	
2.4	d) Number of operating days		365	20,952.3
3.	Rate Base value			460,001.8
4.	Gross return component	(See page 3 of this schedule)		9.36%
5.	Carrying cost requirement			43,056.2

Calculation of the Gross Rate
of Return on Rate Base

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

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

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

INFLATION FACTOR

1. The purpose of this evidence is to provide the inflation factor used in the Company's revenue cap per customer incentive regulation formula. The Company has calculated the inflation factor for 2009 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 2009. 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 2009 is 1.54%.

Table 1
Calculation of Inflation Factor

Col. 1	*Col. 2*	*Col. 3*
Quarter	Index Value	Annualized Growth Rate
2006 Q1	107.30	
2006 Q2	107.60	
2006 Q3	108.10	
2006 Q4	108.50	
2007 Q1	109.70	
2007 Q2	110.50	
2007 Q3	110.10	1.85%
2007 Q4	110.40	1.75%
2008 Q1	111.00	1.19%
2008 Q2	112.00	1.36%
Average (Rounded to 2 decimal places)		1.54%

CUSTOMER ADDITIONS

1. The purpose of this evidence is to provide the Company's forecast of customer additions for the Company's 2009 Test Year. The Company is forecasting 41,241 customer additions for 2009. This represents a decline of 3,293 customer additions relative to the 2008 forecast of 44,534 customer additions.

2. The customer additions forecast for 2009 has been developed using a grass roots approach. Using economic information and inputs from builders, regional operations provide a bottom up forecast of the expected number of customer additions for the upcoming year. This approach has been used by the Company for over a decade in previous rate applications and replicates a process that has been accepted in settlement proposals and Board decisions.

Economy

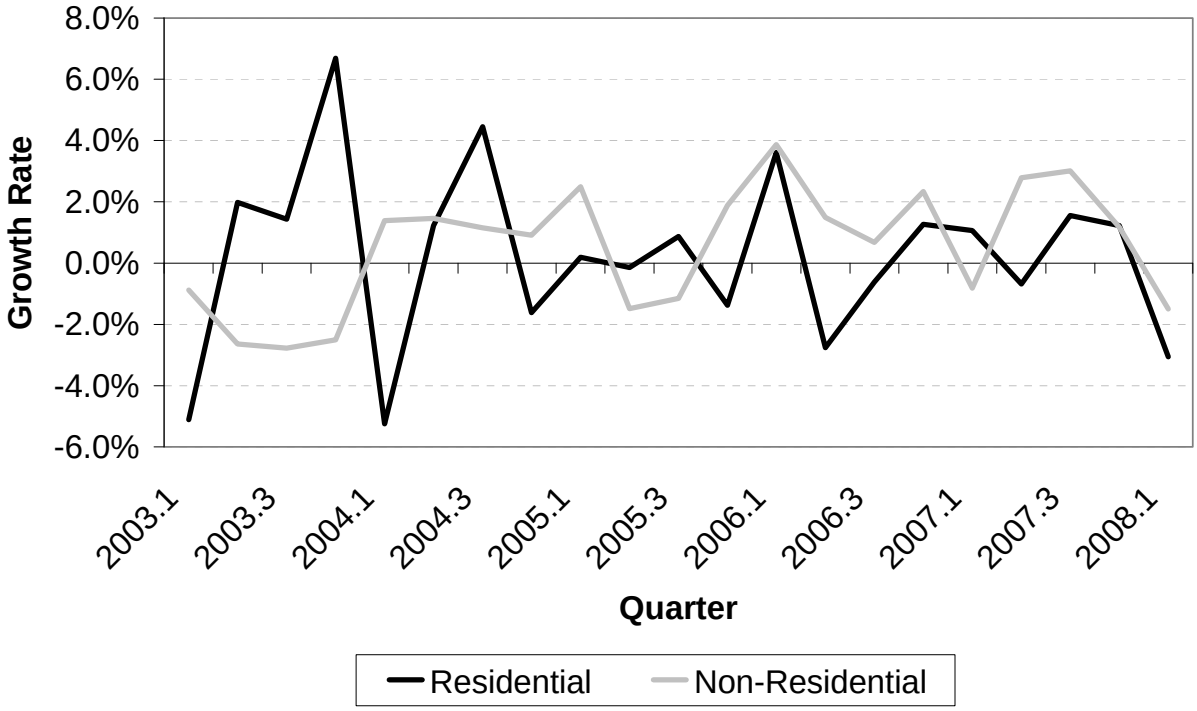
3. Economic conditions in Ontario have deteriorated since the latter half of 2007 and the first quarter of 2008. In the first quarter of 2008, Ontario real gross domestic product declined, quarter over quarter, by 0.3% or 1.4% annualized. This decline in economic output can be partially attributed to a slowing U.S. economy and a high Canadian dollar. The manufacturing sector, particularly the automotive sector and exports, have weakened as a result. Projections for real GDP growth over the next two years for Ontario are on average lower than the growth rates seen for the past five years. Table 1 contains a summary of the Company's Economic Outlook Spring 2008. Detailed tables outlining the Economic Outlook can be found at Exhibit C, Tab 2, Schedule 3, pages 21 to 24.

Table 1
Economic Outlook Summary

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Variable	2003	2004	2005	2006	2007	2008 Forecast	2009 Forecast
ONTARIO REAL GDP (% CHANGE)	1.6	2.9	2.6	2.3	2.0	1.4	2.1
MORTGAGE RATE 5 YEAR TERM (%)	6.39	6.23	5.99	6.66	7.07	6.88	6.68
ONTARIO HOUSING STARTS (000's)	85.2	85.1	78.8	73.4	68.1	64.6	62.3
CENTRAL REGION HOUSING STARTS (000's)	48.1	44.7	43.0	38.8	35.7	40.3	36.2
EASTERN REGION HOUSING STARTS (000's)	6.5	7.5	5.2	6.1	6.8	6.6	6.3
NIAGARA REGION HOUSING STARTS (000's)	1.8	2.0	1.5	1.4	1.3	1.3	1.2
FRANCHISE AREA HOUSING STARTS (000's)	56.4	54.2	49.7	46.3	43.8	48.2	43.7

4. Commensurate with the slowing of overall economic growth, Ontario real business fixed investment in both residential and non-residential construction has also slowed. With these trends expected to continue throughout the remainder of 2008 and into 2009 both housing starts and the construction of new commercial and industrial structures is expected to slow. Figure 1 shows that the growth rate in real business fixed investment for both residential and non-residential structures has trended downwards over the past few quarters.

Figure 1: Ontario Real Business Fixed Investment

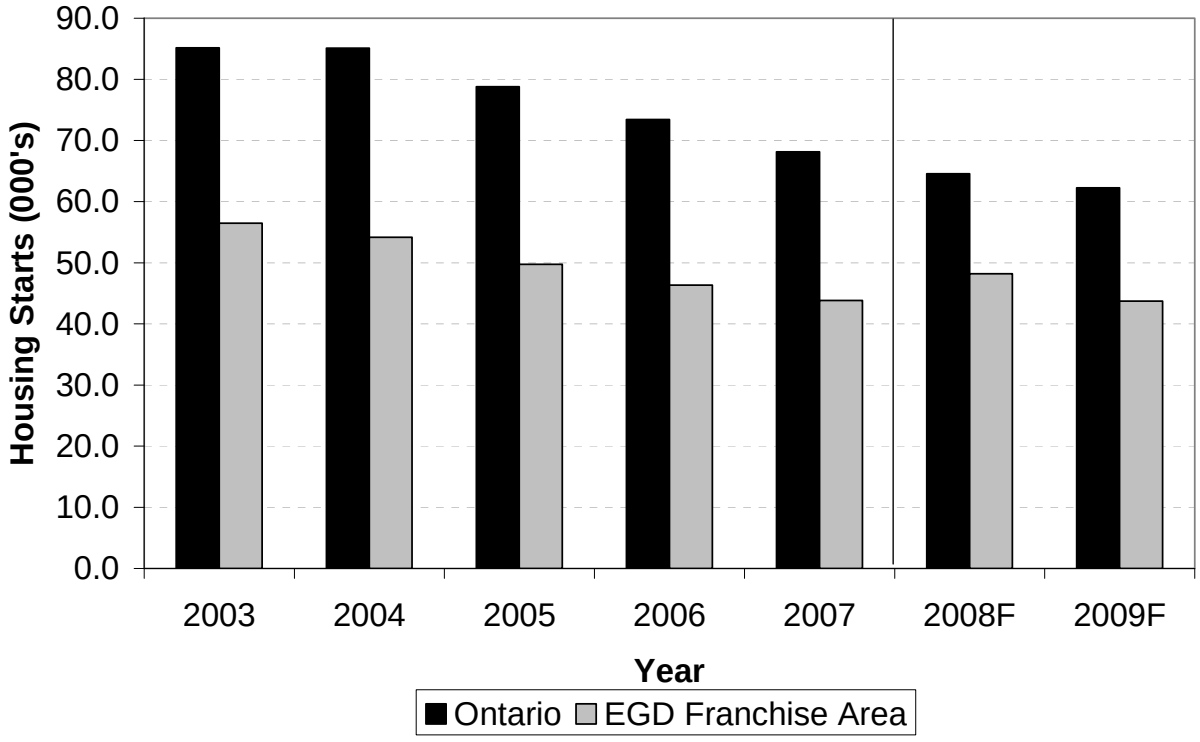


5. The most recent peak in housing starts occurred in 2003. At that point in time the target for the overnight rate set by the Bank of Canada was near historical lows, averaging 2.94% for the year. After declining in 2004 and 2005 the target for the overnight rate set by the Bank of Canada has, on average, increased and consequently mortgage rates have trended upwards as well. Higher interest rates translate into higher financing costs for houses and commercial structures and consequently higher carrying costs should put downward pressure on housing starts and business construction. Table 1 provides the Company's outlook for mortgage rates.

Housing Market

6. Over the past five years housing starts in Ontario and the Company's franchise area have trended down since reaching a peak in 2003. The Company expects this trend to continue over the next two years. Throughout this time period approximately 64% of Ontario housing starts, on average, have resided in the Company's franchise area. Table 1 shows the Company's forecast of housing starts for 2008 and 2009. The Company expects a total of 43,718 housing starts to occur within its franchise area in 2009. The increase shown for 2008 can be attributed to a recent surge in apartment housing starts in Toronto. Figure 2 shows the general downward trend in housing starts for Ontario and the Company's franchise area since 2003.

Figure 2: Housing Start Trends



7. In addition to higher interest rates, Bank lending and credit conditions have recently tightened making it more difficult to obtain financing for a house. In an attempt to circumvent the potential for a U.S. like housing slump, the Canadian Department of Finance recently announced changes to its mortgage insurance guarantee framework. Specific amendments include the increase of required down payment from 0% to 5% (100% loan to value ratio decreased to a 95% loan to value ratio), and a shortening of the maximum allowable amortization period from 40 years to 35 years. Other amendments include establishment of a minimum credit score of 620 and minimum loan documentation standards. These tighter credit conditions will likely cause fewer housing starts than otherwise would occur.

8. Furthermore, the new construction market is at risk from the resale market. The ratio of new home listings in Ontario to housing starts in Ontario has increased from 3.4 in 2003 to 5.1 in 2007. Dramatic increases in the number of existing homes listed for sale has offered home buyers more options and increased competition for developers of new homes.

Residential Customer Additions

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 are comprised of residential customer additions, trends in total customer additions will follow trends in the housing market. Commensurate with the observed decline in housing starts in the Company's franchise area, residential customer additions have followed a similar trend. This trend is expected to continue in 2009. The Company is forecasting 38,287 residential customer additions for 2009. This forecast is comprised of 31,739 new construction customer additions and 6,548 replacement customer additions.

Apartment Customer Additions

10. Over the first quarter of 2008 it became apparent that there is a boom in apartment starts in Toronto. Toronto apartment starts increased 166% relative to the fourth quarter of 2007 and 789% relative to the first quarter of 2007. These trends are expected to continue throughout the remainder of 2008 and into 2009. The Company is forecasting 48 apartment customer additions in 2009. Of this number, 41 are new construction customer additions and 7 are replacement customer additions.

Commercial Customer Additions

11. A slowing economy and higher interest rates are expected to put downward pressure on business fixed investment in commercial non-residential structures. The Company is currently forecasting 2,896 commercial customer additions for 2009. This forecast is comprised of 1,955 new construction customer additions and 941 replacement customer additions.

Industrial Customer Additions

12. Much like the commercial sector, the expectation of a slowing economy and higher interest rates will slow business fixed investment in non-residential structures for the industrial sector. In addition, the manufacturing sector in Ontario is under pressure from a high Canadian dollar and foreign competition. Recent plant closing announcements by GM and O-I Canada are indicative of difficult economic and financial situation faced by industry in Ontario. The Company is forecasting 10 industrial customer additions for 2009, eight of which are new construction customer additions and two of which are replacement customer additions.

13. Table 2 provides the Company's forecast of customer additions for 2009. In summary, a slower economy and the expectation of a continued downward trend in housing starts are expected to cause customer additions to decline to a level of 41,241 in 2009. This represents a decline of 3,293 customer additions relative to the Company's 2008 customer additions forecast.

Table 2
Customer Additions

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Sector	2007 Actual	2008 Board Approved Budget	2009 Forecast
Residential			
New Construction	32,900	33,897	31,739
Replacement	7,008	7,092	6,548
Total	39,908	40,989	38,287
Apartment			
New Construction	5	43	41
Replacement	5	17	7
Total	10	60	48
Commercial			
New Construction	1,943	2,381	1,955
Replacement	1,050	1,086	941
Total	2,993	3,467	2,896
Industrial			
New Construction	6	13	8
Replacement	3	5	2
Total	9	18	10
Total Customer Additions	42,920	44,534	41,241

GAS VOLUME BUDGET

1. The purpose of this evidence is to present the 2009 Test Year forecast of volumes and related information. This evidence is on a calendar-year billing-period basis (i.e., on a December fiscal year end basis) excluding the Historical Actual vs. Board Approved section. The 2009 forecast of gas volumes incorporates calendar 2007 actual billing consumption.

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

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

	2007 Board Approved Budget	2007 Actual	2008 Board Approved Budget	2008 Bridge Year Estimate	2009 Budget
General Service Volumes	7 642.2	8 314.8	8 288.0	8 362.5	9 083.2
Contract Volumes	4 134.3	3 758.5	3 555.2	3 203.0	2 316.6
Total Volumes, Gas Sales and Transportation	11 776.5	12 073.3	11 643.2	11 565.5	11 399.8
Customers, Gas Sales and Transportation (Average)	1 823 258	1 824 789	1 864 047	1 865 004	1 906 437

Witnesses: I. Chan
T. Ladanyi

3. As a consequence of the implementation of NGEIR in 2007 (Natural Gas Electricity Interface Review), the Company has experienced customer migration from bundled rate classes that have gas distribution volumes, reported in Table 1 on the previous page to unbundled rate classes (e.g. Rate 125, Rate 300) that do not have distribution volumes, but do have monthly contract demand volumes. Since these contract demand volumes also generate fixed contract demand revenues, Table 2 below presents a summary of these contract demand volumes. A further explanation of these items is provided at Exhibit B, Tab 3, Schedule 9.

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

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

Comparison of 2009 Budget and 2008 Estimate - Summary

4. The 2009 Budget volumes reflect the meter reading heating degree days forecast for the Central Region of 3,514, a decrease of 29 degree days compared to the 2008 Bridge Year Estimate or 2008 Board Approved of 3,543. Meter reading heating degree days are acquired 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 2, Schedule 1. The 2009 degree day forecast is calculated using the 20-Year Trend methodology that was approved by the Board in its EB-2006-0034 Decision with Reasons.

Witnesses: I. Chan
T. Ladanyi

5. The 2009 Budget volumes of 11 399.8 10^6m^3 are forecast to be 165.7 10^6m^3 or 1.4% below the 2008 Bridge Year Estimate of 11 565.5 10^6m^3. This decline in volumes is attributable to the lower degree days forecast mentioned above and other factors that will be discussed below. On a weather-normalized basis, the 2009 Budget volumes are forecast to be 117.5 10^6m^3 or 1.0% under the 2008 Bridge Year Estimate. The decrease on a normalized basis is made up of an increase in general service volumes of 752.4 10^6m^3 and a decrease in the contract market of 869.9 10^6m^3. Further rate class detail and explanations are provided at Appendix A, pages 1 to 6.

6. The increase in the general service volumes of 752.4 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 722.8 10^6m^3, customer growth of 112.5 10^6m^3 and the Company's incremental added load initiatives of 0.5 10^6m^3. These customer growth and added load volumes help to mitigate the lower average use per customer of 69.0 10^6m^3 resulting from the impact of the Board Approved three-year Demand Side Management ("DSM") plan per the EB-2006-0021 Decision with Reasons, conservation initiatives originated by customers themselves or promoted by government programs, further change in Ontario building codes in 2009, and an anticipated increase in natural gas prices between the 2009 Budget and the 2008 Bridge Year Estimate. Further explanations are provided in the general service volumes section on the next several pages.

7. The decrease of 869.9 10^6m^3 in the contract market on a weather-normalized basis is mainly caused by rate switching from a contract rate to general service rate class (or transfer losses) of 722.8 10^6m^3 and one large distributed energy customer with distribution volume of 98.3 10^6m^3 migrating effective July 1, 2008 from Rate 115

(bundled rate class) to Rate 125 (unbundled rate class that has no distribution volume). After removing the unfavourable rate switching volumetric impact, the 2009 contract market volume budget is expected to be 48.8 10^6m^3 lower than the 2008 Estimate. This underage is primarily due to a loss in load of 37.8 10^6m^3 relating to plant closures or relocations and reduction in usage of 22.2 10^6m^3, partially offset by an addition of rate switching (or transfer gain) from general service rate class to a contract rate class of 14.4 10^6m^3, and the Company's incremental added load initiatives of 1.9 10^6m^3.

8. These ongoing contract market customer losses and reductions in usage reflect recent years' experience of unfavourable economic or business conditions, such as volatile and high gas and oil prices, strong Canadian dollar and global competitive cost pressures experienced in energy intensive industries, such as pulp & paper, transportation equipment, and primary metals. Recent slowing growth in the United States during the first quarter, due to its subprime mortgage issues, has further exacerbated this declining trend. Further explanations are provided in the contract market volumes section on the next several pages.

9. The shift between contract and general service rate classes seen in the 2009 Budget is a continuation of recent trends starting in the fall of 2006 and has been reflected in both 2008 and 2009 volumes. Overall, the 2009 budget represents the forecast that integrates all the actual experience and the best known information about contract customers at the time of the development of the budget.

General Service Demand Forecast Methodology

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

11. Consistent with previous rate cases, the Company is committed to continue reporting the results that the models would generate using the actual data and driver variable information to allow parties to compare the results to the prior year's forecast as agreed in RP-2000-0040 Settlement Agreement at Issue 1.1. Average in-sample forecast error for both Rate 1 and Rate 6 regression models is still less than 1 percent on average during 2001 to 2007 as demonstrated at Exhibit B, Tab 2, Schedule 2. Overall, the regression model has continued to be an excellent predictor of general service average use.

12. Annual econometric models were employed to model and quantify the impact of various driver variables on average use per customer. The forecast incorporated economic assumptions from *Economic Outlook, Spring 2008* at Exhibit B, Tab 2, Schedule 2. This was the latest information available at the time the forecast was developed. As average use regression models are on an annualized basis, the forecast includes 2007 actual billing consumption information up to and including December 2007.

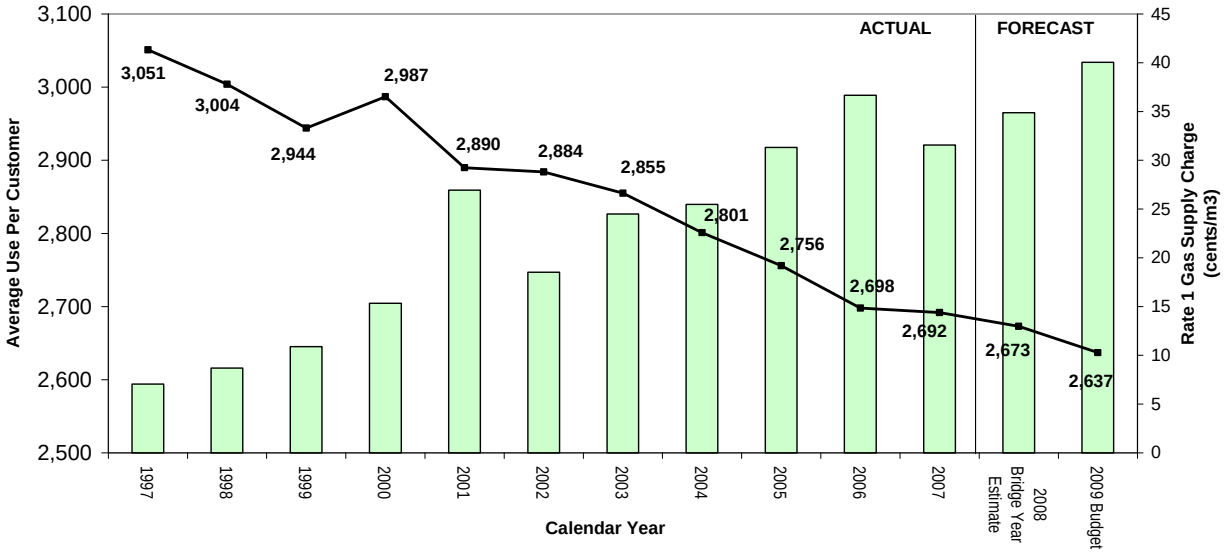
13. The major driver variables in the Rate 1 and Rate 6 models are heating degree days, vintage (Rate 1 only), employment, Ontario real gross domestic product, Ontario real gross domestic product by manufacturing industry, time trend, vacancy rates (Rate 6 only), and real energy prices. The vintage variable was constructed to reflect the impact of new homes associated with more energy efficient gas

equipment over time. Gas equipment includes gas furnaces, water heaters, and stoves. The employment and other economic variables reflect the fact that additional gas appliances, such as pool heaters, would be more affordable under favourable economic conditions, in conjunction with the Company's added load initiatives such as fuel switching, would increase average use. The time trend 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 and conservation initiatives originated by customers themselves or promoted by government programs. Tables of these driver variables assumptions can be found at Exhibit B, Tab 2, Schedule 2.

General Service Volumes: 2009 Budget

14. From 1997 to 2007, normalized residential average use has declined by an average of 36.0 m^3 or 1.24% per year for each residential customer. However, during the volatile and high natural gas price period between 2001 and 2006, normalized residential average use has decreased by an average of 48.0 m^3 or 1.7% per year for each residential customer. Figure 1 below shows the residential average use from 1997 to the 2009 Test Year, on a weather normalized basis, as filed at Appendix A, page 21.

Figure 1
Residential Normalized Average Use (m^3)



15. Table 3 on page 9 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 40.0 10^6m^3 is a result of positive customer growth, partially offset by the ongoing average use decline as shown in Figure 1 above and discussed in the following paragraphs.

16. Compared with the 2008 Bridge Year Estimate, residential average uses will continue to decline in 2009. This decline is due to higher gas prices predicted in 2009 than in 2008 due to the following:
    - the Company's DSM initiatives:

- other conservation initiatives originated by customers themselves or promoted by government programs (e.g.. ecoENERGY Retrofit, Solar H2Ottawa, Ontario Home Energy Audit and Retrofit, and Ontario Solar Thermal Heating Incentive.);
- space heating and water efficiency gains due to ongoing furnace stock turnover and new construction additions with more energy efficient furnaces;
- new homes with improved thermal envelopes based upon the historical 1997 Building Code;
- the new 2006 Building Code effective December 31, 2006; and
- further change to this 2006 Building Code effective December 31, 2008; partially offset by:
- the Company's added load initiatives; and
- the penetration of new gas appliances as a result of positive employment growth in 2009.

Table 3

Factors Influencing the Changes in Residential Gas Consumption

Between 2009 Test Year Budget and 2008 Bridge Year Estimate (10^6m^3)

Factors	Total Volume (10^6m^3)	
Customer Growth	101.2	
DSM Initiatives	(15.1)	
Gas Prices	(13.8)	
New Homes - historical trend (a)	(22.3)	
New Homes - 2006 Building Code (b) - 2009 impact	(2.4)	
Other Conservation (c)	(8.1)	
Gas Appliances (d)	0.0	*
Growth Initiatives or Added Load (e)	0.5	
Total	40.0	

(a) Measured by vintage variable, reflecting the historical impacts of improved building envelopes for new homes along with more efficient new space heating furnaces and water heaters on average uses based upon both historical building code and the new 2006 Building Code for new homes effective December 31, 2006.

(b) Incremental impact of further change to the 2006 Building Code for requiring the near-full-height basement insulation in new homes effective December 31, 2008

(c) 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, etc.

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

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

* Less than 50,000 m^3

17. On June 28, 2006, the Government of Ontario introduced a new 2006 Building Code to increase energy-efficiency requirements for both residential and non-residential buildings relative to the existing 1997 Building Code to be effective December 31, 2006. This new building code will set a new requirement for more

energy efficient windows, higher insulation levels or improved building envelopes, and a higher efficiency rating of 90% for gas and propane-fired instead of the current minimum 78% efficiency requirement. All else being equal, the Government of Ontario estimated that a structure built under this new Building Code will be 21.5% more efficient than the one built under the 1997 Building Code. Further building code changes related to energy efficiency will be phased in during 2009 for requiring near-full-height basement insulation and in 2012 the requirement for meeting standards in accordance with the national guideline, EnerGuide 80.[1]

18. Based upon historical actual data to 2007, the regression model will not be able to predict an incremental average use reduction reflecting the near-full-height basement insulation in new houses between the new building code effective 2008 and the old code. Consequently, the incremental impact of 2.4 $10^6 m^3$ shown in Table 2 is layered onto the regression model's average use forecast. It is calculated by applying the Government of Ontario's estimated savings of 6.5% between 2008 and 2009 to the residential new construction customers that have space heating furnaces.

19. As most of the new customers will not move to their new houses and start consuming gas effective January 1 2009, the currently reported 2.4 $10^6 m^3$ impact reflects the first year's partially effective impact. Beyond 2009, the fully effective impact of this new building code will be much larger than this first year's impact, all else being equal. In addition to these changes in energy-efficiency requirements for buildings, this new 2006 Building Code also includes new provisions that will promote the use of green technologies such as active solar hot water systems,

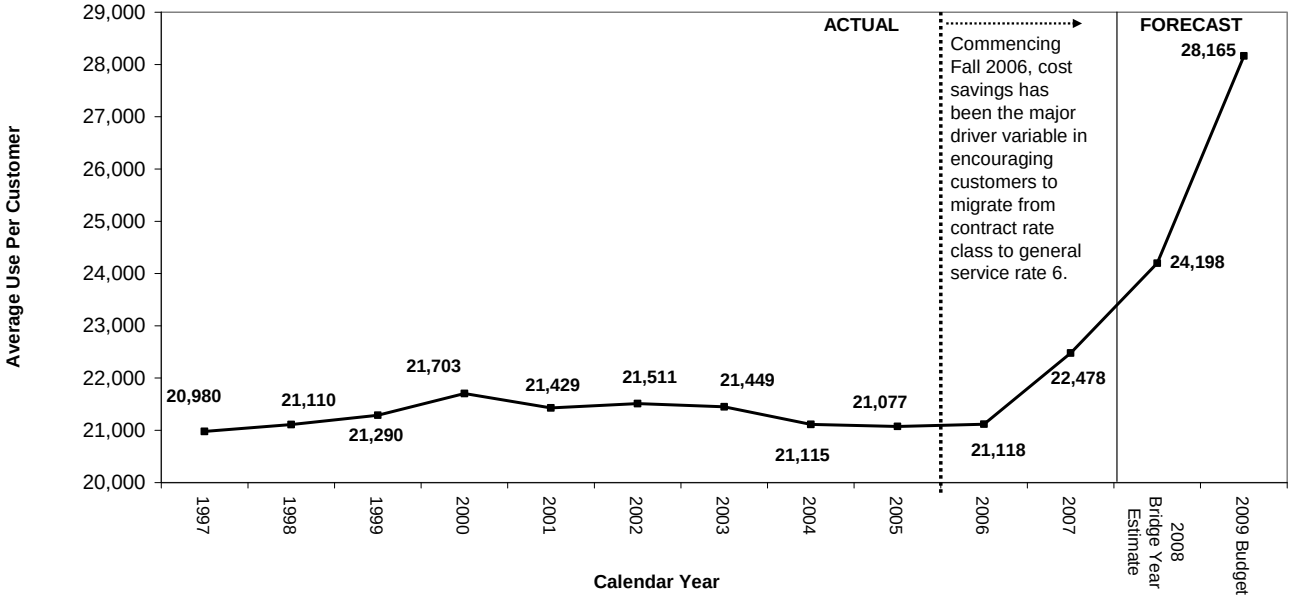
[1] Please refer to the Ministry of Municipal Affairs and Housing web site for further technical information, http://www.mah.gov.on.ca/Page681.aspx.

which can displace natural gas water heater usage in the future. As there is insufficient information available from the Government of Ontario in order to apply the estimated energy savings of these green technologies, the risk of incurring larger residential volume loss than budgeted is weighted heavily to the downside.

20. Rate 6 is comprised of the apartment, commercial, and industrial sectors. From 1997 to 2007, normalized Rate 6 average use has increased by an average of 150 m^3 or 0.7% per year. The increase in 2007 actual usage is largely attributable to the rate switching from contract customers to general service customers starting in the fall of 2006. The anticipated continuation of this trend is the primary reason for the dramatic surge in 2009 of Rate 6 average use budget numbers. Further explanation about this rate switching trend will be presented later.

21. Figure 2 below shows the Rate 6 average use from 1997 to the 2009 Test Year on a test year weather normalized basis, as filed at Appendix A, page 21. Excluding the rate switching, impacted by new factors that are much higher than the historical trend, during the high and volatile natural gas price period between 2001 and 2006, normalized Rate 6 average use has decreased by an average of 98.0 m^3 or 0.45% per year. With the current volatile and unpredictable migration trend, an average use factor that is solely based upon general service rate class is quite misleading when the total volume is in fact unchanged, all else being equal.

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



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

23. Customers typically sign a contract for one year, and the customer is made aware of the minimum bill penalties if the total consumption is below 340,000 m^3. Every year, account executives will review contracts with customers. If customers' prior year or future years' consumption does not meet the minimum threshold requirement, customers would opt for switching to general service rates in order to

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

24. In addition to the factors mentioned above, the rate switching trend has been increased by new factors starting in the fall of 2006 as mentioned in the response to an Undertaking at EB-2006-0034, Exhibit J4.10 and 2008 Gas Volume Budget Evidence at EB-2007-0615, Exhibit C, Tab 2, Schedule 2. These new factors are the introduction and enforcement of new large volume contracts along with Appendix A of the Company's Rate Handbook for each terminal location during 2006 as well as the rate design change for Rates 100 and 145 by requesting them to pay contract demand charges effective April 1, 2007.

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

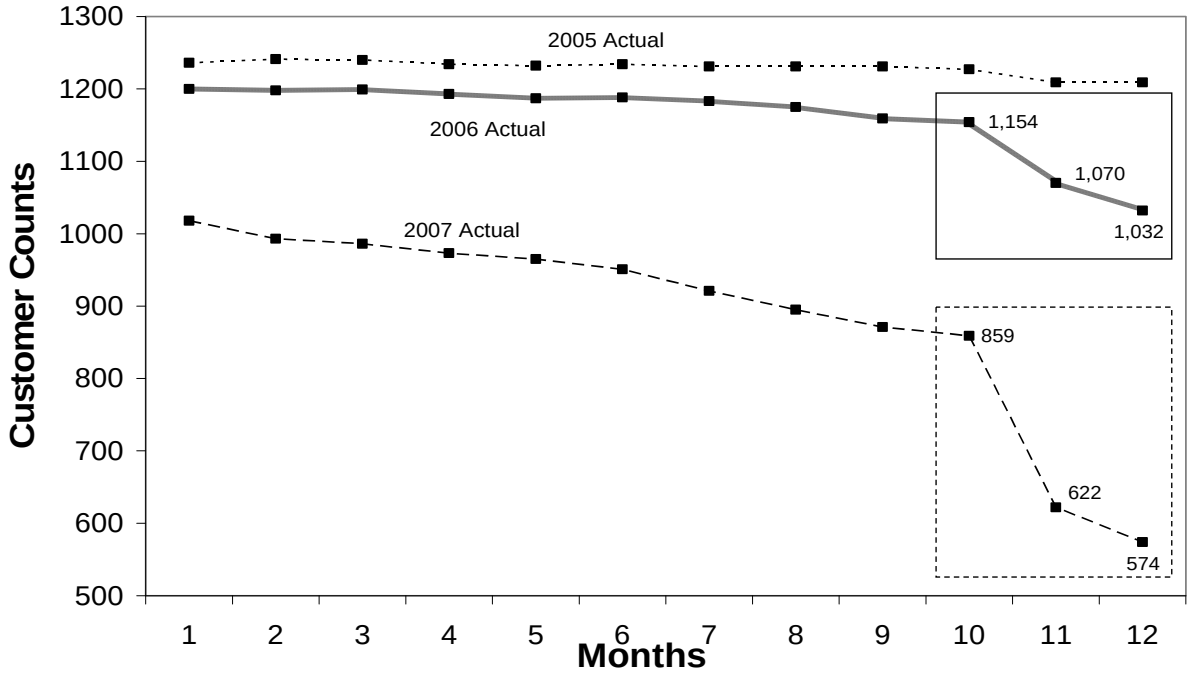


Figure 4: Contract Market Unlock Customers
Commercial Sector

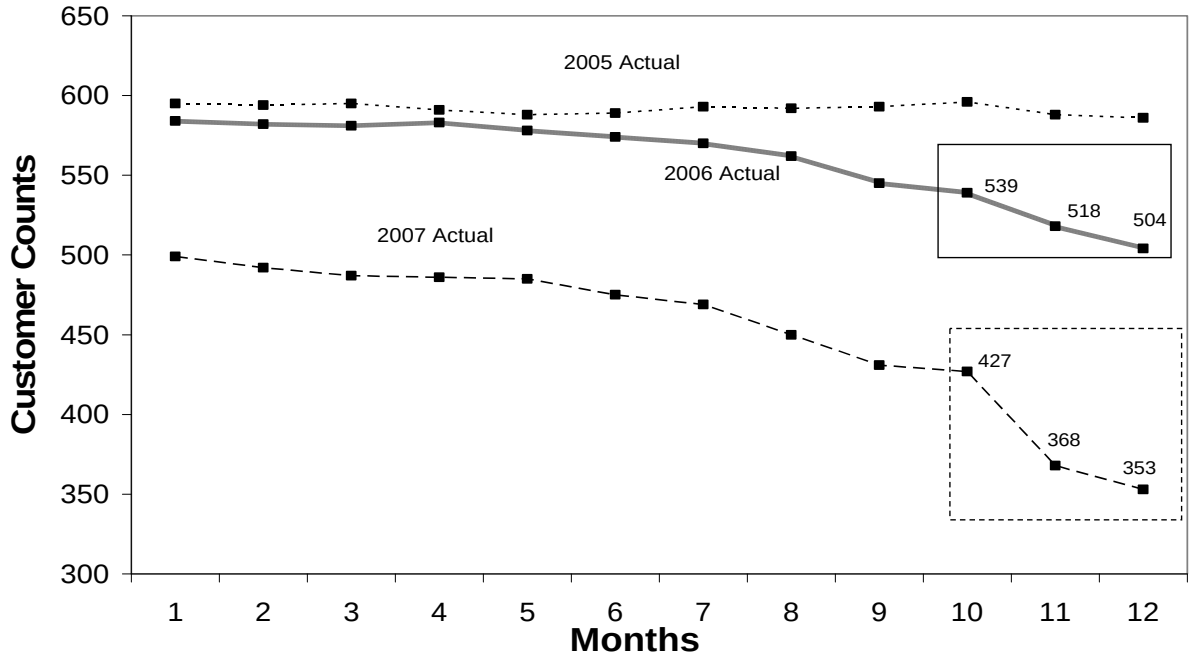
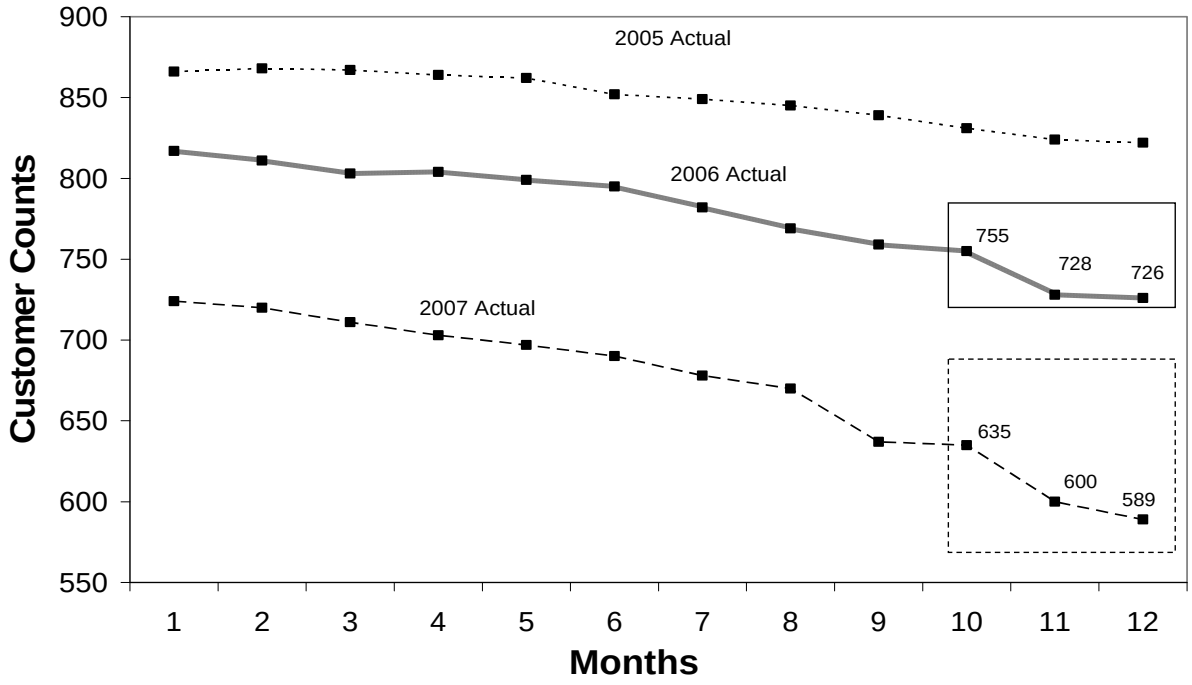


Figure 5: Contract Market Unlock Customers
Industrial Sector

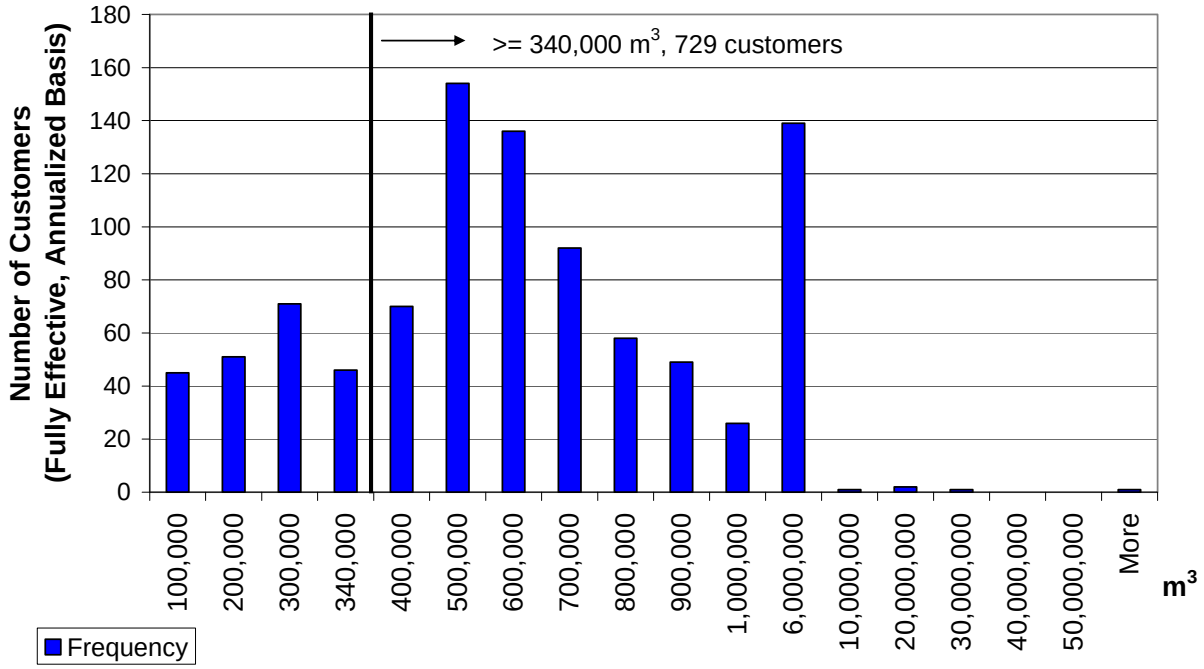


26. Over and above the factors mentioned above, another change to the rate design that was accepted in the Incentive Regulation Settlement Agreement at EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, pages 33 and 34 and was not known when preparing 2008 Volume Budget, has further diminished the cost difference between general service and contract rate classes for remaining contract customers. Specifically, this rate design change reflects the implementation of increasing monthly customer charges for Rate 1 and Rate 6 on a revenue neutral basis by reducing variable charges accordingly and increasing both fixed and variable charges for other rate classes. Consequently, all existing Rate 100 customers will experience a reduction in rate impact by migrating from Rate 100 to Rate 6. In addition, these customers will no longer have to incur monthly fixed contract demand charges and minimum bill penalties in the situation of consuming gas less

than their forecast or contracted volumes. This is especially important to customers who are currently facing volatile and unfavourable business environments.

27. For instance, Figure 6 below displays one Rate 100 contract of 27.1 10^6m^3 and one Rate 110 contract of 51.3 10^6m^3 of two large auto customers who will migrate to Rate 6 effective September 2008 and January 2009, respectively. This migration will not only enable them to reduce energy expenses but will also help them to avoid paying either minimum bill penalties or monthly fixed contract demand charges when the plant is idle or during reduced production as experienced over the past three years.

Figure 6
Customer Migration from Contract Rate Class
(i.e. > Rate 100) to General Service Rate 6 in 2009 = 722.8 10^6m^3



Witnesses: I. Chan
T. Ladanyi

28. The reason why these new rate switching factors are different from the previous years is that the rate switching that occurred in the past was primarily as a consequence of customers not meeting the annual threshold volume of 340,000 m^3. The reason behind recent years' switching is that customers are receiving the financial benefits of migrating from their existing contract rate classes to general service Rate 6 even though their annual volume exceeds the volume threshold mentioned above. Figure 6 above presents the frequency distribution of the customers that are forecast to migrate from contract rate classes to general service Rate 6 (transfer gain only) between the 2009 Budget and the 2008 Bridge Year Estimate. Holding all other things constant, this increases the Rate 6 average use considerably as most of these customers consume more than 340,000 m^3 annually.

29. Based upon historical actual data to 2007, the regression model will not be able to predict the 2009 Budget rate switching for a heterogeneous customer mix that has different individual usage pattern as discussed above. Therefore, both the 2008 estimate and the 2009 budget volumes for these contract customers are layered onto the regression model's average use forecast.

30. Tables 4 to 6 on the next several pages quantify the volumetric impact of the average use's driver variables on the apartment, commercial and industrial sector's average use forecast and customer growth, respectively. On a weather-normalized basis, the increase in the Rate 6 volumes of 712.5 $10^6 m^3$ is in consequence of rate switching from contract market customers, positive customer and employment growth, partially offset by the Company's DSM initiatives, other conservation initiatives originated by customers themselves or promoted by government programs and higher gas prices in 2009 than in 2008.

31. Unlike the residential sector, the impact of the 2006 Building Code on Rate 6 average use was not incorporated into the 2009 Volume Budget. Even though 2006. Building Code and further change to this code also apply to both non-residential and larger residential buildings, there is insufficient information available from the Government of Ontario in order to apply the estimated energy savings to this heterogeneous customer rate class. All else being equal, the 2009 Rate 6 average use budget is on the high side.

Table 4

Factors Influencing the Changes in Apartment Gas Consumption

Between 2009 Test Year Budget and 2008 Bridge Year Estimate (10^6m^3)

Factors	Total Volume (10^6m^3)	
Customer Growth	1.6	
DSM Initiatives	(8.1)	
Economics, Gas Appliances (a)	7.9	
Rate Switching - change in rate design (b)	245.0	
Other Conservation (c)	0.0	*
Gas Prices	(1.6)	
Total	244.8	

(a) Measured by economic variables as explained at Exhibit B, Tab 2, Schedule 2, to reflect the demand for gas appliances or gas technologies, to capture the historical actual average trend of the apartment's sector average use, such as transfer gains/losses impact on average uses, vacancy rate, construction trend, 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, etc.

* Less than 50,000 m^3

Table 5

Factors Influencing the Changes in Commercial Gas Consumption

Between 2009 Test Year Budget and 2008 Bridge Year Estimate (10^6m^3)

Factors	Total Volume (10^6m^3)
Customer Growth	9.6
DSM Initiatives	(10.1)
Economics, Gas Appliances (a)	15.4
Rate Switching - change in rate design (b)	201.7
Other Conservation (c)	(3.8)
Gas Prices	(0.8)
Total	212.0

(a) Measured by economic variables as explained at Exhibit B, Tab 2, Schedule 2, to reflect the demand for gas appliances or gas technologies, to capture the historical actual average trend of the apartment's sector average use, such as transfer gains/losses impact on average uses, vacancy rate, construction trend, 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, etc.

* Less than 50,000 m^3

Table 6

Factors Influencing the Changes in Industrial Gas Consumption

Between 2009 Test Year Budget and 2008 Bridge Year Estimate (10^6m^3)

Factors	Total Volume (10^6m^3)
Customer Growth	0.1
DSM Initiatives	(2.2)
Economics, Gas Appliances (a)	3.4
Rate Switching - change in rate design (b)	261.7
Other Conservation (c)	(7.2)
Gas Prices	(0.2)
Total	255.6

(a) Measured by economic variables as explained at Exhibit B, Tab 2, Schedule 2, to reflect the demand for gas appliances or gas technologies, to capture the historical actual average trend of the apartment's sector average use, such as transfer gains/losses impact on average uses, vacancy rate, construction trend, 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, etc.

* Less than 50,000 m^3

Contract Market Volume Forecast Methodology

32. The volumes in the contract market were generated through an approved grass roots approach. Volumes are forecast on an individual customer basis by account executives through the consultation with customers during the budget process. Specifically, each account executive reviews the contract attributes (e.g., rate and plan type) with the new customer for each contract in order to ensure that each customer can meet its contracted rate class minimum volume and load factor requirements on a consistent basis. Then, the account executives incorporate all the customer's current economic or industry conditions for the customer's business, predicted economic or industry condition, budgeted degree days and the best known information about contract customers into the budget. The 2008 Bridge Year estimate for contract market customers has incorporated five months of 2008 Actual billing consumption information.

Contract Market Volumes: 2009 Budget

33. As mentioned in previous paragraphs, after removing the unfavourable rate switching from contract customers to general service rate class (or transfer losses) of 722.8 10^6m^3 and one large distributed energy customer migration from Rate 115 to Rate 125 that has no distribution volume of 98.3 10^6m^3 effective July 1, 2008, the 2009 contract market volume budget is expected to be 48.8 10^6m^3 lower than the 2008 Estimate on a weather-normalized basis. This underage is primarily due to a loss in load of 37.8 10^6m^3 relating to either plant closures and relocation outside the franchise area by industrial customers and reduction in usage of 22.2 106 m^3, partially offset by an addition of rate switching (or transfer gain) from general service rate class to contract rate class of 14.4 10^6m^3. Table 7 illustrates major variance drivers contributing to the reduction in contract market volumes between 2009

Budget and 2008 Estimate. Table 8 presents the 2009 Budget lost customers or loss in load by trade group.

34. Overall, the downturn in the U.S. economy due to its subprime mortgage issues, strong Canadian dollar, slumping vehicle sales for the two large auto customers, global competition and rising labour, raw material and energy costs are the major reasons cited by customers for closing the plant, relocating the plant to a lower cost area, consolidating several plants into few or one, and reducing the production. These reasons were also the ongoing factors impacting the industrial sector in particular over the past several years. Figure 7 on the following page depicts the overall declining trend of large volume industrial sector. This is also consistent with the latest 2006 Census report from Statistics Canada that Ontario lost more than 77,000 manufacturing jobs from 2001 to 2006.[2] In particular, the pulp, paper and paperboard mill industries shed 4,600 jobs in Ontario over the five-year period.

[2] Statistics Canada (2008), Canada's Changing Labour Force, 2006 Census. Statistics Canada.

Table 7 - Comparison of Contract Market Volumes
2009 Budget and 2008 Bridge Year Estimate
($10^6 m^3$)

	Col. 1	Col. 2	Col. 3
	2009 Budget	2008 Bridge Year Estimate	2009 Budget Over (Under) 2008 Estimate (1-2)
Contract Market Total Gas Sales and Transportation Volumes	2,316.6	3,203.0	(886.4)
Major Variance Drivers:			
Weather Normalization (Exhibit B, Tab 1, Schedule 5, Appendix A, Page 4)			(16.5)
Increased usage of one landfill customer due to completion of its 12" line			4.5
Fully operational on one ethanol plant and one cogeneration customer newly added in 2008 and in 2007			13.2
Added load of existing customers			1.9
Rate switching: one large distributed energy customer migrates from rate 115 to unbundled rate class (rate 125)			(98.3)
Lost customers (Table 8)			(37.8)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			14.4
Transfer losses - migration of customers from contract rates to general service rate 6			(722.8)
Wholesale customer - price impact, switching use from gas to oil			(11.9)
One large Petroleum customer reduces usage by returning to its normal dual fuel usage			(13.4)
Price impact on distributed energy customers and customers that have on-site cogeneration equipments			(2.1)
Impact of Canadian dollar, economy and global competition on pulp & paper industry			(8.9)
Impact of Canadian dollar, economy and global competition on primary metal and non-metallic mineral industries			(7.0)
Others change in usage (e.g. auto industry, change in production process, economy, conservation initiatives, etc.)			(1.7)
Total Major Variance Drivers:			(886.4)

Table 8 - Lost Customers
Between 2009 Test Year Budget and 2008 Bridge Year Estimate

1. Industrial Plants Closure

Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
(1)	Primary Metal & Machinery	(0.4)
(4)	Pulp & Paper	(32.4)
(1)	Textile Products	(0.4)

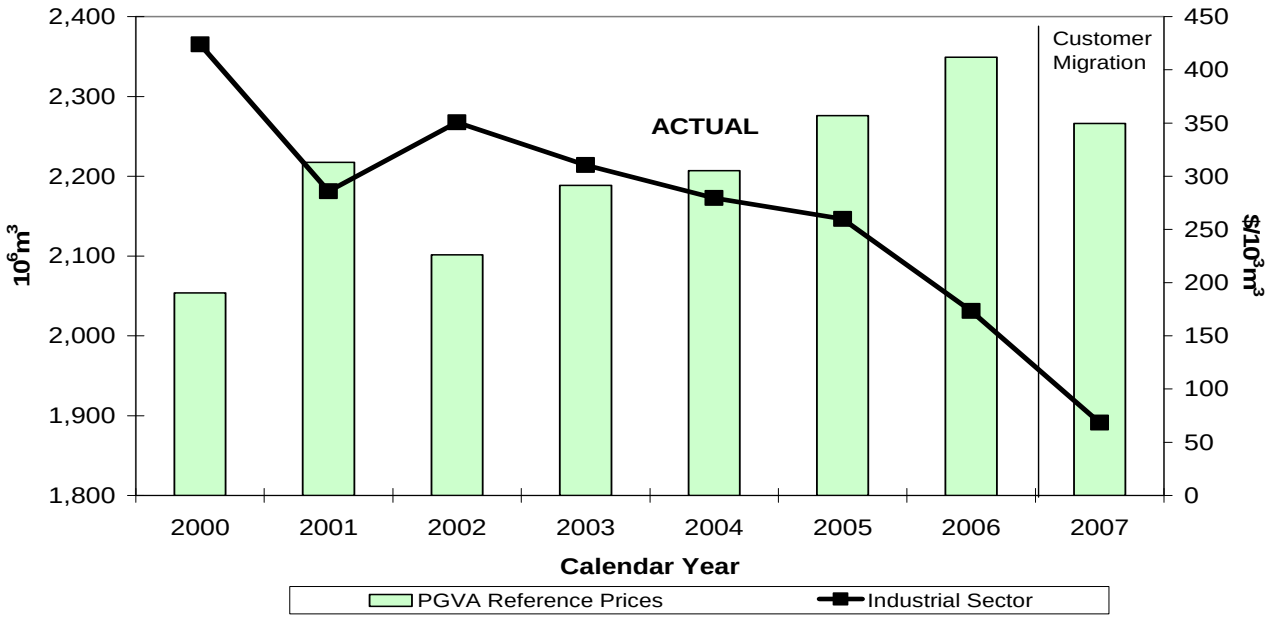
2. Industrial Plants Relocation to Area Outside the Franchise

Number of Customers	Standard Industrial Classification Trade Group	Volume ($10^6 m^3$)
(1)	Asphalt	(1.0)
(2)	Food, Beverage, Drug & Tobacco	(3.5)
(1)	Primary Metal & Machinery	(0.1)

3. Total Lost Customers

(10)		(37.8)

Figure 7
Contract Market Customers - Industrial



35. Specifically, regression models cannot predict when a particular plant will be closed or production shift will be reduced. For instance, one large transportation equipment customer unexpectedly announced production cuts and the phasing out of one of its Ontario plants by Fall 2009 unexpectedly and its Union members were also surprised with these cuts. This is also true to another large food and beverage customer who lately closed one of its plants temporarily due to unforeseen operational issues.

36. Consistent with previous years' filings, the volume budget represents the best information at the time of completion. As the contract market budget was completed in early July, the budget did not incorporate any plant closures after this

date, such as one large customer announced in late July of closing one of its glass container plants in Toronto by October 2008 of 30.2 $10^6 m^3$. With the two large auto customer announcements of either closing the plants or shrinking its production over the past several months, the corresponding impact on Ontario's auto parts manufacturers or suppliers is still unknown. Therefore, the risk of incurring larger industrial volume loss than budgeted is weighted heavily to the downside.

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

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

38. Appendix A, page 26 illustrates 13-Years of Normalized Actual vs. Board Approved volumes to evaluate accuracy of previous forecast for General Service average uses. Other than the unexpected, first time historic high natural gas prices that occurred in 2001 (Figure 1 on page 7) 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 average normalized percentage error variances between 2002 and 2004 as well as 2007 were merely 0.2% or 5 m^3 for Rate 1 use per customer. The Major reasons why Board Approved Budget numbers were higher than the Actuals in recent years were mainly due to the unexpected increase in gas prices in 2001, 2005 and 2006 previously mentioned in the EB-2006-0034

proceeding. This also explains why the Board Approved Budget number for 2007 was lower than the Actual when gas prices were lower than forecast.

39. As discussed in the previous section, unanticipated and unprecedented substantial customer migration from contract rates and general service Rate 6 driven by rate design changes since Fall 2006 was the primary factor that contributed to the Board Approved Budget number being lower than the Actual for Rate 6 in 2007. Both account executives and customers were not aware of the rate design changes effective April 2007 when developing the 2007 Budget during 2006. During the peak contract renewal season (i.e., Fall 2006), customers chose to migrate from contract rates to general service Rate 6 when this would reduce their energy expense. Consequently, other than the unexpected, first time historic high natural gas prices that occurred in 2001 (Figure 1 on page 7) and customer migration that increased volumetric variances significantly, the average normalized percentage error variances between 2002 and 2006 were only 0.2% or 51 m^3 for Rate 6.

40. Appendix A, page 28 illustrates 7-Years of Normalized Actual vs. Board Approved volumes for contract market customers to evaluate accuracy of previous forecast. As contract customer migration between rate classes will fluctuate year over year for various business reasons as indicated in the previous section, the historical accuracy of the volumes and reasonableness would be assessed on the total contract market volume level. Other than the unexpected and historic high natural gas prices that occurred in 2001 and 2006 of reducing gas consumption and causing plant closures along with other unfavourable business factors, as well as unforeseen rate switching that occurred starting Fall 2006 and increased volumetric variances of 333.0 10^6m^3 (net transfer gains and losses between contract rate class and Rate 6 at Appendix A, p. 24) in 2007 significantly, the average normalized

percentage error variance between 2002 and 2005 was only 0.6% or 28 10^6m^3. Excluding the high and volatile gas prices period of 2005, the average normalized percentage error variance between 2002 and 2004 was merely 0.2% or 8 10^6m^3.

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

42. This is evidenced by the unexpected plant closure of one large auto customer in consequence of the parent Company's decision of closing several plants there by conserving cash under the deteriorated business environment. This was also a shock to its own Union and employees. This is one example that has occurred in recent years that the Company's local customers have forecast their volumetric needs on their best projections for their own company. They may not, however, be able to forecast their continued operation within the overall plan of their parent organization as decisions on their viabilities are being made from corporate headquarters.

<u>Comparison of 2008 Estimate and 2007 Actual</u>

43. The Estimate volumes of the 11 565.5 10^6m^3 are forecast to be 507.8 10^6m^3 or 4.2% below the 2007 Actual of 12 073.3 10^6m^3. The unfavourable variance is primarily due to warmer winter weather forecast in 2008 than in 2007. On a weather-normalized basis the 2008 Bridge Year Estimate volumes are 115.6 10^6m^3

or 1.0% below the 2007 Actual. Similar to the explanation above, the underage is mainly caused by one large distributed energy customer migrating from Rate 115 to Rate 125 that has no distribution volume of 94.9 10^6m^3 effective July 1, 2008. After removing this migration, the 2008 Bridge Year Estimate volumes are 20.7 10^6m^3 or 0.2% above the 2007 actual.

44. This negative volumetric variance is primarily driven by ongoing contract market customers' losses relating to either plant closures or consolidation (i.e., relocation outside the franchise area) of 12.8 10^6m^3, a strike at a major U.S. motor vehicle parts supplier and production cuts as its demand crumbled and disrupted one large auto customer's production of 30.2 10^6m^3, impact of the Canadian dollar, economy and global competition on large pulp and paper customers of 12.9 10^6m^3, as well as the usual continued decline in residential average use experienced in the actuals (Figure 1 on page 7) of 32.9 10^6m^3 and wholesale and distributed energy or cogeneration customers unfavourable usage variances of 25.4 10^6m^3 in consequence of anticipated higher gas prices forecast than the 2007 actual; partially offset by customer growth of 137.7 10^6m^3. Further rate class detail is provided at Appendix A, pages 7 to 11.

<u>Comparison of 2008 Estimate and 2008 Board Approved</u>

45. The 2008 Bridge Year Estimate volume has incorporated the full year of 2007 actual information. The Estimate volumes of the 11 565.5 10^6m^3 are forecast to be 77.7 10^6m^3 or 0.7% below the 2008 Board Approved Budget of 11 643.2 10^6m^3. Similar to the explanation above, the shortfall is mainly caused by one large distributed energy customer unexpectedly migrating from Rate 115 to Rate 125 that

has no distribution volume of 103.7 10^6m^3 effective July 1, 2008. After removing this migration, the 2008 Bridge Year Estimate volumes are 26.0 10^6m^3 or 0.2% above the Board Approved Budget.

46. This positive volumetric variance is primarily due to favourable general service average use variance of 60.2 10^6m^3, one wholesale and distributed energy or cogeneration customers favourable usage variances of 42.4 10^6m^3 in consequence of lower gas prices anticipated for this year compared to last year resulting from the lack of significant hurricane activity in the Gulf of Mexico during 2008 and 2007 in contrast to previous years, partially offset by the ongoing contract market customer losses relating to either plant closures or consolidation (i.e., relocation outside the franchise area) of 18.9 10^6m^3, a strike at a major U.S. motor vehicle parts supplier and production cuts as its demand crumbled and disrupted one large auto customer's production of 27.4 10^6m^3, and large pulp and paper customers of 29.3 10^6m^3 for the same reasons explained in previous sections. Further rate class detail is provided at Appendix A, pages 12 to 14.

Comparison of 2007 Actual and 2007 Board Approved

47. When comparing the actual with the Board Approved Budget, the actual volumes of the 12 073.3 10^6m^3 were 296.8 10^6m^3 or 2.5% over the 2007 Board Approved Budget of 11 776.5 10^6m^3. The majority of the increase resulted mainly from significantly colder actual weather experienced during winter months than the Board Approved Degree Days of 3,617 as agreed during the settlement conference process. On a weather-normalized basis, the 2007 actual volumes were merely 1.2 10^6m^3 or 0.01% over the 2007 Board Approved Budget.

48. This positive volumetric variance was attributable to favourable residential average use variances of 66.2 10^6m^3 in the presence of lower actual gas prices than forecast resulting from the lack of significant hurricane activity in the Gulf of Mexico during 2007 in contrast to previous years and favourable general service customer variance of 4.5 10^6m^3, partially offset by contract market customer losses relating to either plant closures or consolidation (i.e., relocation outside the franchise area) of 22.9 10^6m^3, unfavourable usage variances largely driven by two large auto customers of 25.8 10^6m^3 and large pulp and paper customers of 19.9 10^6m^3 for the same reasons explained in previous sections. Further rate class detail is provided at Appendix A, pages 22 to 24.

Weather Normalization Methodology

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

50. General Service normalization is conducted on customers at a group level. The Company's General Service customers are grouped together into homogenous classes of gas usage within the six regions of the Company's franchise area. Only the heat sensitive portion of consumption is normalized for heat sensitive or balance point degree days. Further explanation of the balance point degree days is explained later. An example of the methodology is illustrated below.

51. 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, 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.

52. In the EBRO 465 Decision with Reasons, paragraph 3.1.16 states that the Board accepted the Company's weather normalization methodology and directed the Company to further investigate methods to more effectively segregate its weather sensitive and non-weather sensitive loads. A more effective segregation of load and an enhanced weather normalization methodology that included changing summer base load definition to the average of July and August consumption, performing calculations using new base load/heating load split and include September as a heating load month, was proposed in EBRO 473 and the Board accepted this change in methodology.

53. In EBRO 487, the Company proposed to change from the traditional $18^{O}C$ balance point temperature assumption to a new temperature for purposes of normalizing average general service customer uses. The reason was that results from load research indicated that this $18^{O}C$ balance point assumption was not valid due to technological and building standard environment. The basic conclusion of the

research was that an average balance point value for Central, Niagara, and Eastern weather zones are 14.8^{O}C, 15.3^{O}C and 14.6^{O}C, respectively. That means the new normalization approach only normalizes heating load in the Central weather zone if the temperature falls below 14.8^{O}C.

54. In addition, this proposed new normalizing technique has been very beneficial in reducing the volatility in residential normalized average use for the shoulder months of November and April and, to a lesser extent, October and May. Shoulder months have been important in the overall consideration of average use trends. Unnormalized average uses in the months leading into the winter period and out of the winter period can fluctuate significantly depending on the length of a seasonably warm or cold cycle.

55. As stated in the Decision with Reasons, the Board found the Company's proposals to implement an improved model for heating load analysis when estimating volumetric forecasts was reasonable and acceptable. All intervenors accepted the Company's proposals during the settlement process. They all felt that the proposed changes were a significant improvement over the balance point traditionally used at 18^{o}C or 65 ^{o}F.

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

reduce or to completely eliminate or curtail the use of gas to balance the Company's gas supply and demand requirements under extreme or peak weathers. Therefore, the actual volumes used by customers would have been lower than budgeted and must be increased to the normal level assumed in the budget.

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2009 BUDGET

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	
General Service				
1.1.1	Rate 1 - Sales	1 096 540	2 896.6	
1.1.2	Rate 1 - T-Service	650 555	1 705.0	
1.1	Total Rate 1	1 747 095	4 601.6	
1.2.1	Rate 6 - Sales	103 202	1 819.2	
1.2.2	Rate 6 - T-Service	55 565	2 659.8	
1.2	Total Rate 6	158 767	4 479.0	
1.3.1	Rate 9 - Sales	25	2.1	
1.3.2	Rate 9 - T-Service	3	0.5	
1.3	Total Rate 9	28	2.6	
1.	Total General Service Sales & T-Service	1 905 890	9 083.2	
Contract Sales				
2.1	Rate 100	0	0.0	
2.2	Rate 110	33	71.5	
2.3	Rate 115	1	4.4	
2.4	Rate 135	1	3.3	
2.5	Rate 145	9	22.5	
2.6	Rate 170	4	56.3	
2.7	Rate 200	1	151.3	
2.	Total Contract Sales	49	309.3	
Contract T-Service				
3.1	Rate 100	0	0.0	
3.2	Rate 110	216	619.5	
3.3	Rate 115	47	532.1	
3.4	Rate 125	3	0.0	*
3.5	Rate 135	37	54.8	
3.6	Rate 145	158	203.6	
3.7	Rate 170	27	545.6	
3.8	Rate 300	10	51.7	
3.9	Rate 315	0	0.0	
3.	Total Contract T-Service	498	2 007.3	
4.	Total Contract Sales & T-Service	547	2 316.6	
5.	Total	1 906 437	11 399.8	

* There is no distribution volume for Rate 125 customer.

Witnesses: I. Chan
T. Ladanyi

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

Item No.		Col. 1 2009 Budget	Col. 2 2008 Bridge Year Estimate	Col. 3 2009 Budget Over (Under) 2008 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 096 540	1 071 794	24 746
1.1.2	Rate 1 - T-Service	650 555	636 470	14 085
1.1	Total Rate 1	1 747 095	1 708 264	38 831
1.2.1	Rate 6 - Sales	103 202	101 829	1 373
1.2.2	Rate 6 - T-Service	55 565	53 562	2 003
1.2	Total Rate 6	158 767	155 391	3 376
1.3.1	Rate 9 - Sales	25	25	0
1.3.2	Rate 9 - T-Service	3	3	0
1.3	Total Rate 9	28	28	0
1.	Total General Service Sales & T-Service	1 905 890	1 863 683	42 207
Contract Sales				
2.1	Rate 100	0	118	(118)
2.2	Rate 110	33	29	4
2.3	Rate 115	1	1	0
2.4	Rate 135	1	2	(1)
2.5	Rate 145	9	9	0
2.6	Rate 170	4	5	(1)
2.7	Rate 200	1	1	0
2.	Total Contract Sales	49	165	(116)
Contract T-Service				
3.1	Rate 100	0	650	(650)
3.2	Rate 110	216	217	(1)
3.3	Rate 115	47	50	(3)
3.4	Rate 125	3	2	1
3.5	Rate 135	37	37	0
3.6	Rate 145	158	160	(2)
3.7	Rate 170	27	30	(3)
3.8	Rate 300	10	10	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	498	1 156	(658)
4.	Total Contract Sales & T-Service	547	1 321	(774)
5.	Total	1 906 437	1 865 004	41 433

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

Item No.		Col. 1 2009 Budget	Col. 2 2008 Bridge Year Estimate	Col. 3 2009 Budget Over (Under) 2008 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	2 896.6	2 881.9	14.7
1.1.2	Rate 1 - T-Service	1 705.0	1 694.0	11.0
1.1	Total Rate 1	4 601.6	4 575.9	25.7
1.2.1	Rate 6 - Sales	1 819.2	1 726.0	93.2
1.2.2	Rate 6 - T-Service	2 659.8	2 057.9	601.9
1.2	Total Rate 6	4 479.0	3 783.9	695.1
1.3.1	Rate 9 - Sales	2.1	2.2	(0.1)
1.3.2	Rate 9 - T-Service	0.5	0.5	0.0
1.3	Total Rate 9	2.6	2.7	(0.1)
1.	Total General Service Sales & T-Service	9 083.2	8 362.5	720.7
Contract Sales				
2.1	Rate 100	0.0	95.1	(95.1)
2.2	Rate 110	71.5	71.3	0.2
2.3	Rate 115	4.4	4.7	(0.3)
2.4	Rate 135	3.3	3.3	0.0
2.5	Rate 145	22.5	23.4	(0.9)
2.6	Rate 170	56.3	56.1	0.2
2.7	Rate 200	151.3	163.2	(11.9)
2.	Total Contract Sales	309.3	417.1	(107.8)
Contract T-Service				
3.1	Rate 100	0.0	587.7	(587.7)
3.2	Rate 110	619.5	629.2	(9.7)
3.3	Rate 115	532.1	634.9	(102.8)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	54.8	55.2	(0.4)
3.6	Rate 145	203.6	212.1	(8.5)
3.7	Rate 170	545.6	625.7	(80.1)
3.8	Rate 300	51.7	41.1	10.6
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	2 007.3	2 785.9	(778.6)
4.	Total Contract Sales & T-Service	2 316.6	3 203.0	(886.4)
5.	Total	11 399.8	11 565.5	(165.7)

* There is no distribution volume for Rate 125 customer.

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

Item No.		Col. 1 2009 Budget	Col. 2 2008 Bridge Year Estimate	Col. 3 2009 Budget Over (Under) 2008 Estimate (1-2)	Col. 4 2008* Adjustments	Col. 5 2009 Budget Over (Under) 2008 Estimate with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	2 896.6	2 881.9	14.7	(8.8)	23.5
1.1.2	Rate 1 - T-Service	1 705.0	1 694.0	11.0	(5.5)	16.5
1.1	Total Rate 1	4 601.6	4 575.9	25.7	(14.3)	40.0
1.2.1	Rate 6 - Sales	1 819.2	1 726.0	93.2	(5.8)	99.0
1.2.2	Rate 6 - T-Service	2 659.8	2 057.9	601.9	(11.6)	613.5
1.2	Total Rate 6	4 479.0	3 783.9	695.1	(17.4)	712.5
1.3.1	Rate 9 - Sales	2.1	2.2	(0.1)	0.0	(0.1)
1.3.2	Rate 9 - T-Service	0.5	0.5	0.0	0.0	0.0
1.3	Total Rate 9	2.6	2.7	(0.1)	0.0	(0.1)
1.	Total General Service Sales & T-Service	9 083.2	8 362.5	720.7	(31.7)	752.4
Contract Sales						
2.1	Rate 100	0.0	95.1	(95.1)	(0.1)	(95.0)
2.2	Rate 110	71.5	71.3	0.2	0.0 **	0.2
2.3	Rate 115	4.4	4.7	(0.3)	0.0 **	(0.3)
2.4	Rate 135	3.3	3.3	0.0	0.0 **	0.0
2.5	Rate 145	22.5	23.4	(0.9)	(0.4)	(0.5)
2.6	Rate 170	56.3	56.1	0.2	(1.2)	1.4
2.7	Rate 200	151.3	163.2	(11.9)	0.0 **	(11.9)
2.	Total Contract Sales	309.3	417.1	(107.8)	(1.7)	(106.1)
Contract T-Service						
3.1	Rate 100	0.0	587.7	(587.7)	(1.0)	(586.7)
3.2	Rate 110	619.5	629.2	(9.7)	(0.2)	(9.5)
3.3	Rate 115	532.1	634.9	(102.8)	0.0 **	(102.8)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	54.8	55.2	(0.4)	0.0 **	(0.4)
3.6	Rate 145	203.6	212.1	(8.5)	(3.9)	(4.6)
3.7	Rate 170	545.6	625.7	(80.1)	(9.7)	(70.4)
3.8	Rate 300	51.7	41.1	10.6	0.0	10.6
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	2 007.3	2 785.9	(778.6)	(14.8)	(763.8)
4.	Total Contract Sales & T-Service	2 316.6	3 203.0	(886.4)	(16.5)	(869.9)
5.	Total	11 399.8	11 565.5	(165.7)	(48.2)	(117.5)

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

** Less than 50,000 m^3.

Witnesses: I. Chan
T. Ladanyi

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

Item No.		Col. 1 2009 Budget	Col. 2 2008 Bridge Year Estimate	Col. 3 2009 Budget Over (Under) 2008 Estimate (1-2)	Col. 4 Change in Use	Col. 5 Weather	Col. 6 New Customers	Col. 7 Transfer Gains	Col. 8 Transfer Losses	Col. 9 Lost Customers	Col. 10 Added Load
General Service											
1.1.1	Rate 1 - Sales	2 896.6	2 881.9	14.7	(41.5)	(8.8)	64.5	0.0	0.0	0.0	0.5
1.1.2	Rate 1 - T-Service	1 705.0	1 694.0	11.0	(20.2)	(5.5)	36.7	0.0	0.0	0.0	0.0
1.1	Total Rate 1	4 601.6	4 575.9	25.7	(61.7)	(14.3)	101.2	0.0	0.0	0.0	0.5
1.2.1	Rate 6 - Sales	1 819.2	1 726.0	93.2	(9.7)	(5.8)	11.3	97.4	0.0	0.0	0.0
1.2.2	Rate 6 - T-Service	2 659.8	2 057.9	601.9	2.5	(11.6)	0.0	625.4	(14.4)	0.0	0.0
1.2	Total Rate 6	4 479.0	3 783.9	695.1	(7.2)	(17.4)	11.3	722.8	(14.4)	0.0	0.0
1.3.1	Rate 9 - Sales	2.1	2.2	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.3	Total Rate 9	2.6	2.7	(0.1)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0
1.	Total General Service	9 083.2	8 362.5	720.7	(69.0)	(31.7)	112.5	722.8	(14.4)	0.0	0.5
Contract Sales											
2.1	Rate 100	0.0	95.1	(95.1)	0.0	(0.1)	0.0	0.0	(95.0)	0.0	0.0
2.2	Rate 110	71.5	71.3	0.2	0.2	0.0 *	0.0	0.0	0.0	0.0	0.0
2.3	Rate 115	4.4	4.7	(0.3)	(0.3)	0.0 *	0.0	0.0	0.0	0.0	0.0
2.4	Rate 135	3.3	3.3	0.0	0.0	0.0 *	0.0	0.0	0.0	0.0	0.0
2.5	Rate 145	22.5	23.4	(0.9)	0.0	(0.4)	0.0	0.0	(0.5)	0.0	0.0
2.6	Rate 170	56.3	56.1	0.2	1.4	(1.2)	0.0	0.0	0.0	0.0	0.0
2.7	Rate 200	151.3	163.2	(11.9)	(11.9)	0.0 *	0.0	0.0	0.0	0.0	0.0
2.	Total Contract Sales	309.3	417.1	(107.8)	(10.6)	(1.7)	0.0	0.0	(95.5)	0.0	0.0
Contract T-Service											
3.1	Rate 100	0.0	587.7	(587.7)	2.9	(1.0)	0.0	0.0	(588.0)	(1.6)	0.0
3.2	Rate 110	619.5	629.2	(9.7)	10.9	(0.2)	0.0	15.5	(34.1)	(2.1)	0.3
3.3	Rate 115	532.1	634.9	(102.8)	(1.5)	0.0 *	0.0	0.8	(100.1)	(2.0)	0.0
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	54.8	55.2	(0.4)	0.6	0.0 *	0.0	0.0	0.0	(1.0)	0.0
3.6	Rate 145	203.6	212.1	(8.5)	(4.0)	(3.9)	0.0	2.1	(2.1)	(2.2)	1.6
3.7	Rate 170	545.6	625.7	(80.1)	(31.0)	(9.7)	0.0	0.0	(10.5)	(28.9)	0.0
3.8	Rate 300	51.7	41.1	10.6	10.6	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	2 007.3	2 785.9	(778.6)	(11.6)	(14.8)	0.0	18.4	(734.8)	(37.8)	1.9
4.	Total Contract Sales & T-Service	2 316.6	3 203.0	(886.4)	(22.2)	(16.5)	0.0	18.4	(830.3)	(37.8)	1.9
5.	Total	11 399.8	11 565.5	(165.7)	(91.2)	(48.2)	112.5	741.2	(844.7)	(37.8)	2.4

* Less than 50,000 m^3.

The principal reasons for the variances contributing to the weather normalized decrease of 117.5 10^6m^3 in the 2009 Budget over the 2008 Bridge Year Estimate are as follows:

1. The volumetric increase of 40.0 10^6m^3 in Rate 1 is due to customer growth of 101.2 10^6m^3; partially offset by a lower average use per customer totalling 61.2 10^6m^3;

2. The volumetric increase of 712.5 10^6m^3 in Rate 6 is due to customer growth of 11.3 10^6m^3, net customer migration from Contract Sales and T-Service of 708.4 10^6m^3; partially offset by a lower average use per customer totalling 7.2 10^6m^3;

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

4. The volumetric decrease for Contract Sales and T-Service of 869.9 10^6m^3 is due to decreases in the apartment sector of 255.6 10^6m^3, the commercial sector of 275.6 10^6m^3, the industrial sector of 326.8 10^6m^3 and Rate 200 of 11.9 10^6m^3. This decrease is primarily attributable to net customer migration to General Service of 708.4 10^6m^3 as stated above as well as one large distributed energy customer with distribution volume of 98.3 10^6m^3 migrating from Rate 115 to Rate 125 that has no distribution volume effective July 1, 2008.

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2008 BRIDGE YEAR ESTIMATE

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	
General Service				
1.1.1	Rate 1 - Sales	1 071 794	2 881.9	
1.1.2	Rate 1 - T-Service	636 470	1 694.0	
1.1	Total Rate 1	1 708 264	4 575.9	
1.2.1	Rate 6 - Sales	101 829	1 726.0	
1.2.2	Rate 6 - T-Service	53 562	2 057.9	
1.2	Total Rate 6	155 391	3 783.9	
1.3.1	Rate 9 - Sales	25	2.2	
1.3.2	Rate 9 - T-Service	3	0.5	
1.3	Total Rate 9	28	2.7	
1.	Total General Service Sales & T-Service	1 863 683	8 362.5	
Contract Sales				
2.1	Rate 100	118	95.1	
2.2	Rate 110	29	71.3	
2.3	Rate 115	1	4.7	
2.4	Rate 135	2	3.3	
2.5	Rate 145	9	23.4	
2.6	Rate 170	5	56.1	
2.7	Rate 200	1	163.2	
2.	Total Contract Sales	165	417.1	
Contract T-Service				
3.1	Rate 100	650	587.7	
3.2	Rate 110	217	629.2	
3.3	Rate 115	50	634.9	
3.4	Rate 125	2	0.0	*
3.5	Rate 135	37	55.2	
3.6	Rate 145	160	212.1	
3.7	Rate 170	30	625.7	
3.8	Rate 300	10	41.1	
3.9	Rate 315	0	0.0	
3.	Total Contract T-Service	1 156	2 785.9	
4.	Total Contract Sales & T-Service	1 321	3 203.0	
5.	Total	1 865 004	11 565.5	

* There is no distribution volume for Rate 125 customer.

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

Item No.		Col. 1 2008 Bridge Year Estimate	Col. 2 2007 Actual	Col. 3 2008 Estimate Over (Under) 2007 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 071 794	1 019 738	52 056
1.1.2	Rate 1 - T-Service	636 470	650 448	(13 978)
1.1	Total Rate 1	1 708 264	1 670 186	38 078
1.2.1	Rate 6 - Sales	101 829	97 335	4 494
1.2.2	Rate 6 - T-Service	53 562	55 217	(1 655)
1.2	Total Rate 6	155 391	152 552	2 839
1.3.1	Rate 9 - Sales	25	26	(1)
1.3.2	Rate 9 - T-Service	3	4	(1)
1.3	Total Rate 9	28	30	(2)
1.	Total General Service Sales & T-Service	1 863 683	1 822 768	40 915
Contract Sales				
2.1	Rate 100	118	192	(74)
2.2	Rate 110	29	27	2
2.3	Rate 115	1	4	(3)
2.4	Rate 135	2	1	1
2.5	Rate 145	9	11	(2)
2.6	Rate 170	5	4	1
2.7	Rate 200	1	1	0
2.	Total Contract Sales	165	240	(75)
Contract T-Service				
3.1	Rate 100	650	1 266	(616)
3.2	Rate 110	217	235	(18)
3.3	Rate 115	50	57	(7)
3.4	Rate 125	2	1	1
3.5	Rate 135	37	37	0
3.6	Rate 145	160	148	12
3.7	Rate 170	30	28	2
3.8	Rate 300	10	9	1
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	1 156	1 781	(625)
4.	Total Contract Sales & T-Service	1 321	2 021	(700)
5.	Total	1 865 004	1 824 789	40 215

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

Item No.		Col. 1 2008 Bridge Year Estimate	Col. 2 2007 Actual	Col. 3 2008 Estimate Over (Under) 2007 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	2 881.9	2 872.9	9.0
1.1.2	Rate 1 - T-Service	1 694.0	1 818.2	(124.2)
1.1	Total Rate 1	4 575.9	4 691.1	(115.2)
1.2.1	Rate 6 - Sales	1 726.0	1 644.3	81.7
1.2.2	Rate 6 - T-Service	2 057.9	1 976.8	81.1
1.2	Total Rate 6	3 783.9	3 621.1	162.8
1.3.1	Rate 9 - Sales	2.2	2.0	0.2
1.3.2	Rate 9 - T-Service	0.5	0.6	(0.1)
1.3	Total Rate 9	2.7	2.6	0.1
1.	Total General Service Sales & T-Service	8 362.5	8 314.8	47.7
Contract Sales				
2.1	Rate 100	95.1	141.8	(46.7)
2.2	Rate 110	71.3	30.2	41.1
2.3	Rate 115	4.7	43.1	(38.4)
2.4	Rate 135	3.3	3.2	0.1
2.5	Rate 145	23.4	23.6	(0.2)
2.6	Rate 170	56.1	63.6	(7.5)
2.7	Rate 200	163.2	174.1	(10.9)
2.	Total Contract Sales	417.1	479.6	(62.5)
Contract T-Service				
3.1	Rate 100	587.7	899.4	(311.7)
3.2	Rate 110	629.2	577.8	51.4
3.3	Rate 115	634.9	851.6	(216.7)
3.4	Rate 125	0.0	0.0	0.0
3.5	Rate 135	55.2	53.2	2.0
3.6	Rate 145	212.1	208.5	3.6
3.7	Rate 170	625.7	654.7	(29.0)
3.8	Rate 300	41.1	33.7	7.4
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	2 785.9	3 278.9	(493.0)
4.	Total Contract Sales & T-Service	3 203.0	3 758.5	(555.5)
5.	Total	11 565.5	12 073.3	(507.8)

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

Item No.		Col. 1 2008 Bridge Year Estimate	Col. 2 2007 Actual	Col. 3 2008 Estimate Over (Under) 2007 Actual (1-2)	Col. 4 2007* Adjustments	Col. 5 2008 Estimate Over (Under) 2007 Actual with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	2 881.9	2 872.9	9.0	(115.1)	124.1
1.1.2	Rate 1 - T-Service	1 694.0	1 818.2	(124.2)	(69.5)	(54.7)
1.1	Total Rate 1	4 575.9	4 691.1	(115.2)	(184.6)	69.4
1.2.1	Rate 6 - Sales	1 726.0	1 644.3	81.7	(66.1)	147.8
1.2.2	Rate 6 - T-Service	2 057.9	1 976.8	81.1	(100.1)	181.2
1.2	Total Rate 6	3 783.9	3 621.1	162.8	(166.2)	329.0
1.3.1	Rate 9 - Sales	2.2	2.0	0.2	0.0	0.2
1.3.2	Rate 9 - T-Service	0.5	0.6	(0.1)	0.0	(0.1)
1.3	Total Rate 9	2.7	2.6	0.1	0.0	0.1
1.	Total General Service Sales & T-Service	8 362.5	8 314.8	47.7	(350.8)	398.5
Contract Sales						
2.1	Rate 100	95.1	141.8	(46.7)	(3.6)	(43.1)
2.2	Rate 110	71.3	30.2	41.1	(0.1)	41.2
2.3	Rate 115	4.7	43.1	(38.4)	0.0 **	(38.4)
2.4	Rate 135	3.3	3.2	0.1	0.0 **	0.1
2.5	Rate 145	23.4	23.6	(0.2)	(0.3)	0.1
2.6	Rate 170	56.1	63.6	(7.5)	(0.1)	(7.4)
2.7	Rate 200	163.2	174.1	(10.9)	(1.5)	(9.4)
2.	Total Contract Sales	417.1	479.6	(62.5)	(5.6)	(56.9)
Contract T-Service						
3.1	Rate 100	587.7	899.4	(311.7)	(26.0)	(285.7)
3.2	Rate 110	629.2	577.8	51.4	(1.2)	52.6
3.3	Rate 115	634.9	851.6	(216.7)	0.1	(216.8)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	55.2	53.2	2.0	0.0 **	2.0
3.6	Rate 145	212.1	208.5	3.6	(3.5)	7.1
3.7	Rate 170	625.7	654.7	(29.0)	(5.2)	(23.8)
3.8	Rate 300	41.1	33.7	7.4	0.0	7.4
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	2 785.9	3 278.9	(493.0)	(35.8)	(457.2)
4.	Total Contract Sales & T-Service	3 203.0	3 758.5	(555.5)	(41.4)	(514.1)
5.	Total	11 565.5	12 073.3	(507.8)	(392.2)	(115.6)

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

** Less than 50,000 m^3.

Witnesses: I. Chan
T. Ladanyi

The principal reasons for the variances contributing to the weather normalized decrease of 115.6 10^6m^3 in the 2008 Bridge Year Estimate over the 2007 Actual are as follows:

1. The volumetric increase of 69.4 10^6m^3 in Rate 1 is due to customer growth of 102.3 10^6m^3; partially offset by a lower average use per customer totalling 32.9 10^6m^3;

2. The volumetric increase of 329.0 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 357.6 10^6m^3, customer growth of 12.2 10^6m^3 and partially offset by a lower average use per customer totalling 40.8 10^6m^3;

3. The volumetric increase of 0.1 10^6m^3 in Rate 9 is due to a higher average use per station totalling 0.2 10^6m^3; partially offset by the loss of two stations of 0.1 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 514.1 10^6m^3 is due to decreases in the apartment sector of 172.0 10^6m^3, the commercial sector of 85.5 10^6m^3, the industrial sector of 247.2 10^6m^3 and Rate 200 of 9.4 10^6m^3. This decrease is primarily attributable to net customer migration to General Service of 357.6 10^6m^3 as stated above as well as one large distributed energy customer with distribution volume of 94.9 10^6m^3 migrating from Rate 115 to Rate 125 that has no distribution volume effective July 1, 2008.

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

Item No.		Col. 1 2008 Bridge Year Estimate	Col. 2 2008 Board Approved Budget	Col. 3 2008 Estimate Over (Under) 2008 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	2 881.9	2 783.0	98.9
1.1.2	Rate 1 - T-Service	1 694.0	1 736.2	(42.2)
1.1	Total Rate 1	4 575.9	4 519.2	56.7
1.2.1	Rate 6 - Sales	1 726.0	1 619.0	107.0
1.2.2	Rate 6 - T-Service	2 057.9	2 147.1	(89.2)
1.2	Total Rate 6	3 783.9	3 766.1	17.8
1.3.1	Rate 9 - Sales	2.2	2.0	0.2
1.3.2	Rate 9 - T-Service	0.5	0.7	(0.2)
1.3	Total Rate 9	2.7	2.7	0.0
1.	Total General Service Sales & T-Service	8 362.5	8 288.0	74.5
Contract Sales				
2.1	Rate 100	95.1	87.9	7.2
2.2	Rate 110	71.3	24.0	47.3
2.3	Rate 115	4.7	46.2	(41.5)
2.4	Rate 135	3.3	3.3	0.0 **
2.5	Rate 145	23.4	30.8	(7.4)
2.6	Rate 170	56.1	62.1	(6.0)
2.7	Rate 200	163.2	150.0	13.2
2.	Total Contract Sales	417.1	404.3	12.8
Contract T-Service				
3.1	Rate 100	587.7	569.7	18.0
3.2	Rate 110	629.2	588.9	40.3
3.3	Rate 115	634.9	854.9	(220.0)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	55.2	50.9	4.3
3.6	Rate 145	212.1	187.4	24.7
3.7	Rate 170	625.7	667.2	(41.5)
3.8	Rate 300	41.1	31.9	9.2
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	2 785.9	2 950.9	(165.0)
4.	Total Contract Sales & T-Service	3 203.0	3 355.2	(152.2)
5.	Total	11 565.5	11 643.2	(77.7)

* There is no distribution volume for Rate 125 customer.
** Less than 50,000 m^3

Witnesses: I. Chan
T. Ladanyi

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

Item No.		Col. 1 2008 Bridge Year Estimate	Col. 2 2008 Board Approved Budget	Col. 3 2008 Estimate Over (Under) 2008 Budget (1-2)	Col. 4 2008* Adjustments	Col. 5 2008 Estimate Over (Under) 2008 Budget with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	2 881.9	2 783.0	98.9	0.0	98.9
1.1.2	Rate 1 - T-Service	1 694.0	1 736.2	(42.2)	0.0	(42.2)
1.1	Total Rate 1	4 575.9	4 519.2	56.7	0.0	56.7
1.2.1	Rate 6 - Sales	1 726.0	1 619.0	107.0	0.0	107.0
1.2.2	Rate 6 - T-Service	2 057.9	2 147.1	(89.2)	0.0	(89.2)
1.2	Total Rate 6	3 783.9	3 766.1	17.8	0.0	17.8
1.3.1	Rate 9 - Sales	2.2	2.0	0.2	0.0	0.2
1.3.2	Rate 9 - T-Service	0.5	0.7	(0.2)	0.0	(0.2)
1.3	Total Rate 9	2.7	2.7	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	8 362.5	8 288.0	74.5	0.0	74.5
Contract Sales						
2.1	Rate 100	95.1	87.9	7.2	0.0	7.2
2.2	Rate 110	71.3	24.0	47.3	0.0	47.3
2.3	Rate 115	4.7	46.2	(41.5)	0.0	(41.5)
2.4	Rate 135	3.3	3.3	0.0	0.0	0.0 **
2.5	Rate 145	23.4	30.8	(7.4)	0.0	(7.4)
2.6	Rate 170	56.1	62.1	(6.0)	0.0	(6.0)
2.7	Rate 200	163.2	150.0	13.2	0.0	13.2
2.	Total Contract Sales	417.1	404.3	12.8	0.0	12.8
Contract T-Service						
3.1	Rate 100	587.7	569.7	18.0	0.0	18.0
3.2	Rate 110	629.2	588.9	40.3	0.0	40.3
3.3	Rate 115	634.9	854.9	(220.0)	0.0	(220.0)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	55.2	50.9	4.3	0.0	4.3
3.6	Rate 145	212.1	187.4	24.7	0.0	24.7
3.7	Rate 170	625.7	667.2	(41.5)	0.0	(41.5)
3.8	Rate 300	41.1	31.9	9.2	0.0	9.2
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	2 785.9	2 950.9	(165.0)	0.0	(165.0)
4.	Total Contract Sales & T-Service	3 203.0	3 355.2	(152.2)	0.0	(152.2)
5.	Total	11 565.5	11 643.2	(77.7)	0.0	(77.7)

*Note: As 2008 Bridge Year Estimate degree days are same as 2008 Board Approved Budget Degree Days, normalization adjustment is not required in order to place the two years on a comparable basis.

** Less than 50,000 m^3

Witnesses: I. Chan
T. Ladanyi

The principal reasons for the variances contributing to the weather normalized decrease of 77.7 10^6m^3 in the 2008 Bridge Year Estimate over the 2008 Board Approved Budget are as follows:

1. The volumetric increase of 56.7 10^6m^3 in Rate 1 is due to a higher average use per customer totalling 55.1 10^6m^3 and favourable customer variance of 1.6 10^6m^3;

2. The volumetric increase of 17.8 10^6m^3 in Rate 6 is due to a higher average use per customer totalling 5.0 10^6m^3 and net customer migration from Contract Sales and T-Service of 12.8 10^6m^3;

3. There was no volumetric change in Rate 9, in consequence of an increase in average use per station of 0.1 10^6m^3 that is completely offset by a loss in one station of 0.1 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 152.2 10^6m^3 is due to decreases in the commercial sector of 51.8 10^6m^3 and the industrial sector of 158.2 10^6m^3; partially offset by increases in the apartment sector of 44.6 10^6m^3 and Rate 200 of 13.2 10^6m^3. The decrease is primarily attributable to one large distributed energy customer with distribution volume of 103.7 10^6m^3 migrating from Rate 115 to Rate 125 that has no distribution volume effective July 1, 2008.

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2007 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	1 019 738	2 872.9		1 424.6
1.1.2	Rate 1 - T-Service	650 448	1 818.2		338.8
1.1	Total Rate 1	1 670 186	4 691.1		1 763.4
1.2.1	Rate 6 - Sales	97 335	1 644.3		725.7
1.2.2	Rate 6 - T-Service	55 217	1 976.8		212.8
1.2	Total Rate 6	152 552	3 621.1		938.5
1.3.1	Rate 9 - Sales	26	2.0		0.8
1.3.2	Rate 9 - T-Service	4	0.6		0.1
1.3	Total Rate 9	30	2.6		0.9
1.	Total General Service Sales & T-Service	1 822 768	8 314.8		2 702.8
Contract Sales					
2.1	Rate 100	192	141.8		56.5
2.2	Rate 110	27	30.2		10.6
2.3	Rate 115	4	43.1		14.2
2.4	Rate 135	1	3.2		1.0
2.5	Rate 145	11	23.6		8.5
2.6	Rate 170	4	63.6		19.9
2.7	Rate 200	1	174.1		48.5
2.	Total Contract Sales	240	479.6		159.2
Contract T-Service					
3.1	Rate 100	1 266	899.4		80.1
3.2	Rate 110	235	577.8		35.7
3.3	Rate 115	57	851.6		39.1
3.4	Rate 125	1	0.0	*	1.0
3.5	Rate 135	37	53.2		2.4
3.6	Rate 145	148	208.5		12.3
3.7	Rate 170	28	654.7		21.0
3.8	Rate 300	9	33.7		0.3
3.9	Rate 305	0	0.0	**	0.0
3.10	Rate 315	0	0.0		0.1
3.	Total Contract T-Service	1 781	3 278.9		192.0
4.	Total Contract Sales & T-Service	2 021	3 758.5		351.2
5.	Total	1 824 789	12 073.3		3 054.0

* There is no distribution volume for Rate 125 and Rate 315 customers.
** Rate 305 is no longer a valid rate class effective January 1, 2007 after the implementation of NGEIR.

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2007 ACTUAL AND 2006 ACTUAL - CALENDAR YEAR

Item No.		Col. 1 2007 Actual	Col. 2 2006 Actual	Col. 3 2007 Actual Over (Under) 2006 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 019 738	981 599	38 139
1.1.2	Rate 1 - T-Service	650 448	648 637	1 811
1.1	Total Rate 1	1 670 186	1 630 236	39 950
1.2.1	Rate 6 - Sales	97 335	92 399	4 936
1.2.2	Rate 6 - T-Service	55 217	57 639	(2 422)
1.2	Total Rate 6	152 552	150 038	2 514
1.3.1	Rate 9 - Sales	26	28	(2)
1.3.2	Rate 9 - T-Service	4	6	(2)
1.3	Total Rate 9	30	34	(4)
1.	Total General Service Sales & T-Service	1 822 768	1 780 308	42 460
Contract Sales				
2.1	Rate 100	192	266	(74)
2.2	Rate 110	27	31	(4)
2.3	Rate 115	4	3	1
2.4	Rate 135	1	1	0
2.5	Rate 145	11	19	(8)
2.6	Rate 170	4	3	1
2.7	Rate 200	1	1	0
2.	Total Contract Sales	240	324	(84)
Contract T-Service				
3.1	Rate 100	1 266	1 656	(390)
3.2	Rate 110	235	252	(17)
3.3	Rate 115	57	57	0
3.4	Rate 125	1	0	1
3.5	Rate 135	37	36	1
3.6	Rate 145	148	149	(1)
3.7	Rate 170	28	30	(2)
3.8	Rate 300	9	0	9
3.9	Rate 305	0 *	1	(1)
3.10	Rate 315	0	0	0
3.	Total Contract T-Service	1 781	2 181	(400)
4.	Total Contract Sales & T-Service	2 021	2 505	(484)
5.	Total	1 824 789	1 782 813	41 976

* Rate 305 is no longer a valid rate class effective January 1, 2007 after the implementation of NGEIR.

Witnesses: I. Chan
T. Ladanyi

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2007 ACTUAL AND 2006 ACTUAL
(10^6m^3)

Item No.		Col. 1 2007 Actual		Col. 2 2006 Actual	Col. 3 2007 Actual Over (Under) 2006 Actual (1-2)
General Service					
1.1.1	Rate 1 - Sales	2 872.9		2 621.0	251.9
1.1.2	Rate 1 - T-Service	1 818.2		1 706.6	111.6
1.1	Total Rate 1	4 691.1		4 327.6	363.5
1.2.1	Rate 6 - Sales	1 644.3		1 463.7	180.6
1.2.2	Rate 6 - T-Service	1 976.8		1 695.9	280.9
1.2	Total Rate 6	3 621.1		3 159.6	461.5
1.3.1	Rate 9 - Sales	2.0		2.4	(0.4)
1.3.2	Rate 9 - T-Service	0.6		0.9	(0.3)
1.3	Total Rate 9	2.6		3.3	(0.7)
1.	Total General Service Sales & T-Service	8 314.8		7 490.5	824.3
Contract Sales					
2.1	Rate 100	141.8		174.9	(33.1)
2.2	Rate 110	30.2		40.6	(10.4)
2.3	Rate 115	43.1		41.7	1.4
2.4	Rate 135	3.2		1.0	2.2
2.5	Rate 145	23.6		32.8	(9.2)
2.6	Rate 170	63.6		58.9	4.7
2.7	Rate 200	174.1		164.9	9.2
2.	Total Contract Sales	479.6		514.8	(35.2)
Contract T-Service					
3.1	Rate 100	899.4		1 073.7	(174.3)
3.2	Rate 110	577.8		561.7	16.1
3.3	Rate 115	851.6		896.7	(45.1)
3.4	Rate 125	0.0	*	0.0	0.0
3.5	Rate 135	53.2		56.0	(2.8)
3.6	Rate 145	208.5		198.5	10.0
3.7	Rate 170	654.7		661.7	(7.0)
3.8	Rate 300	33.7		1.3	32.4
3.9	Rate 305	0.0	**	32.0	(32.0)
3.10	Rate 315	0.0		0.0	0.0
3.	Total Contract T-Service	3 278.9		3 481.6	(202.7)
4.	Total Contract Sales & T-Service	3 758.5		3 996.4	(237.9)
5.	Total	12 073.3		11 486.9	586.4

* There is no distribution Volume for Rate 125 customer.
** Rate 305 is no longer a valid rate class effective January 1, 2007 after the implementation of NGEIR.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2007 ACTUAL AND 2006 ACTUAL
(10^6m^3)

Item No.		Col. 1 2007 Actual	Col. 2 2006 Actual	Col. 3 2007 Actual Over (Under) 2006 Actual (1-2)	Col. 4 2006* Adjustments	Col. 5 2007 Actual Over (Under) 2006 Actual with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	2 872.9	2 621.0	251.9	186.1	65.8
1.1.2	Rate 1 - T-Service	1 818.2	1 706.6	111.6	115.0	(3.4)
1.1	Total Rate 1	4 691.1	4 327.6	363.5	301.1	62.4
1.2.1	Rate 6 - Sales	1 644.3	1 463.7	180.6	119.3	61.3
1.2.2	Rate 6 - T-Service	1 976.8	1 695.9	280.9	142.2	138.7
1.2	Total Rate 6	3 621.1	3 159.6	461.5	261.5	200.0
1.3.1	Rate 9 - Sales	2.0	2.4	(0.4)	0.0	(0.4)
1.3.2	Rate 9 - T-Service	0.6	0.9	(0.3)	0.0	(0.3)
1.3	Total Rate 9	2.6	3.3	(0.7)	0.0	(0.7)
1.	Total General Service Sales & T-Service	8 314.8	7 490.5	824.3	562.6	261.7
Contract Sales						
2.1	Rate 100	141.8	174.9	(33.1)	3.2	(36.3)
2.2	Rate 110	30.2	40.6	(10.4)	0.0 **	(10.4)
2.3	Rate 115	43.1	41.7	1.4	0.0 **	1.4
2.4	Rate 135	3.2	1.0	2.2	0.0 **	2.2
2.5	Rate 145	23.6	32.8	(9.2)	0.4	(9.6)
2.6	Rate 170	63.6	58.9	4.7	0.2	4.5
2.7	Rate 200	174.1	164.9	9.2	6.2	3.0
2.	Total Contract Sales	479.6	514.8	(35.2)	10.0	(45.2)
Contract T-Service						
3.1	Rate 100	899.4	1 073.7	(174.3)	23.5	(197.8)
3.2	Rate 110	577.8	561.7	16.1	0.4	15.7
3.3	Rate 115	851.6	896.7	(45.1)	(0.1)	(45.0)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	53.2	56.0	(2.8)	(0.1)	(2.7)
3.6	Rate 145	208.5	198.5	10.0	3.7	6.3
3.7	Rate 170	654.7	661.7	(7.0)	2.2	(9.2)
3.8	Rate 300	33.7	1.3	32.4	0.0	32.4
3.9	Rate 305	0.0	32.0	(32.0)	0.0	(32.0)
3.10	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	3 278.9	3 481.6	(202.7)	29.6	(232.3)
4.	Total Contract Sales & T-Service	3 758.5	3 996.4	(237.9)	39.6	(277.5)
5.	Total	12 073.3	11 486.9	586.4	602.2	(15.8)

* Note: Weather normalization adjustments have been made to the 2006 Actuals utilizing the 2007 actual degree days in order to place the two years on a comparable basis.

** Less than 50,000 m^3.

Witnesses: I. Chan
T. Ladanyi

The principal reasons for the variances contributing to the weather normalized decrease of 15.8 10^6m^3 in the 2007 Actual over the 2006 Actual are as follows:

1. The volumetric increase of 62.4 10^6m^3 in Rate 1 is due to customer growth of 106.4 10^6m^3; partially offset by a lower average use per customer totalling 44.0 10^6m^3;

2. The volumetric increase of 200.0 10^6m^3 in Rate 6 is due to customer growth of 12.8 10^6m^3 and net customer migration from Contract Sales and T-Service of 223.0 10^6m^3; partially offset by a lower average use per customer totalling 35.8 10^6m^3;

3. The volumetric decrease of 0.7 10^6m^3 in Rate 9 is due to a lower average use per station totalling 0.4 10^6m^3 and a loss of four stations of 0.3 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 277.5 10^6m^3 is due to decreases in the apartment sector of 143.0 10^6m^3, the commercial sector of 63.0 10^6m^3, the industrial sector of 74.5 10^6m^3 and partially offset by increase of the Rate 200 of 3.0 10^6m^3. This volumetric decrease is attributable to net customer migration to General Service of 223.0 10^6m^3 as stated above as well as customers migrating from bundled rate classes to unbundled rate classes of 3.1 10^6m^3 in consequence of the implementation of NGEIR.

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008 Bridge Year Estimate	2009 Budget
Residential		3,051	3,004	2,944	2,987	2,890	2,884	2,855	2,801	2,756	2,698	2,692	2,673	2,637
	Change		(47)	(60)	43	(97)	(6)	(29)	(54)	(45)	(58)	(6)	(19)	(36)
	% Change		-1.54%	-2.00%	1.46%	-3.25%	-0.21%	-1.01%	-1.89%	-1.61%	-2.10%	-0.22%	-0.71%	-1.35%
Apartment		77,321	80,221	79,798	79,630	80,114	81,639	82,381	82,373	81,469	86,137	100,899	111,840	139,022
	Change		2,900	(423)	(168)	484	1,525	742	(8)	(904)	4,668	14,762	10,941	27,182
	% Change		3.75%	-0.53%	-0.21%	0.61%	1.90%	0.91%	-0.01%	-1.10%	5.73%	17.14%	10.84%	24.30%
Commercial		16,791	16,702	16,929	17,342	17,160	17,355	17,136	16,991	16,913	16,749	17,228	17,575	18,698
	Change		(89)	227	413	(182)	195	(219)	(145)	(78)	(164)	479	347	1,123
	% Change		-0.53%	1.36%	2.44%	-1.05%	1.14%	-1.26%	-0.85%	-0.46%	-0.97%	2.86%	2.01%	6.39%
Industrial		51,109	53,677	54,912	57,858	56,072	52,875	55,476	50,956	53,632	53,885	59,280	78,829	116,198
	Change		2,568	1,235	2,946	(1,786)	(3,197)	2,601	(4,520)	2,676	253	5,395	19,549	37,369
	% Change		5.02%	2.30%	5.36%	-3.09%	-5.70%	4.92%	-8.15%	5.25%	0.47%	10.01%	32.98%	47.41%

* All historical average uses are on a calendar-year basis and have been normalized to the 2009 Budget degree days.

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008 Bridge Year Estimate	2009 Budget
Rate 1		3,051	3,004	2,944	2,987	2,890	2,884	2,855	2,801	2,756	2,698	2,692	2,673	2,637
	Change		(47)	(60)	43	(97)	(6)	(29)	(54)	(45)	(58)	(6)	(19)	(36)
	% Change		-1.54%	-2.00%	1.46%	-3.25%	-0.21%	-1.01%	-1.89%	-1.61%	-2.10%	-0.22%	-0.71%	-1.35%
Rate 6		20,980	21,110	21,290	21,703	21,429	21,511	21,449	21,115	21,077	21,118	22,478	24,198	28,165
	Change		130	180	413	(274)	82	(62)	(334)	(38)	41	1,360	1,720	3,967
	% Change		0.62%	0.85%	1.94%	-1.26%	0.38%	-0.29%	-1.56%	-0.18%	0.19%	6.44%	7.65%	16.39%

* All historical average uses are on a calendar-year basis and have been normalized to the 2009 Budget degree days.

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

Item No.		Col. 1 2007 Actual	Col. 2 2007 Board Approved Budget	Col. 3 2007 Actual Over (Under) 2007 Board Approved Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	2 872.9	2 763.1	109.8
1.1.2	Rate 1 - T-Service	1 818.2	1 723.0	95.2
1.1	Total Rate 1	4 691.1	4 486.1	205.0
1.2.1	Rate 6 - Sales	1 644.3	1 446.4	197.9
1.2.2	Rate 6 - T-Service	1 976.8	1 702.3	274.5
1.2	Total Rate 6	3 621.1	3 148.7	472.4
1.3.1	Rate 9 - Sales	2.0	5.4	(3.4)
1.3.2	Rate 9 - T-Service	0.6	2.0	(1.4)
1.3	Total Rate 9	2.6	7.4	(4.8)
1.	Total General Service Sales & T-Service	8 314.8	7 642.2	672.6
Contract Sales				
2.1	Rate 100	141.8	218.7	(76.9)
2.2	Rate 110	30.2	50.0	(19.8)
2.3	Rate 115	43.1	41.7	1.4
2.4	Rate 135	3.2	5.2	(2.0)
2.5	Rate 145	23.6	41.3	(17.7)
2.6	Rate 170	63.6	57.5	6.1
2.7	Rate 200	174.1	150.7	23.4
2.	Total Contract Sales	479.6	565.1	(85.5)
Contract T-Service				
3.1	Rate 100	899.4	1 169.9	(270.5)
3.2	Rate 110	577.8	570.4	7.4
3.3	Rate 115	851.6	864.5	(12.9)
3.4	Rate 125	0.0	0.0	0.0
3.5	Rate 135	53.2	50.2	3.0
3.6	Rate 145	208.5	210.5	(2.0)
3.7	Rate 170	654.7	672.5	(17.8)
3.8	Rate 300	33.7	0.0	33.7
3.9	Rate 305	0.0 *	31.2	(31.2)
3.10	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	3 278.9	3 569.2	(290.3)
4.	Total Contract Sales & T-Service	3 758.5	4 134.3	(375.8)
5.	Total	12 073.3	11 776.5	296.8

* Rate 305 is no longer a valid rate class effective January 1, 2007 after the implementation of NGEIR.

Witnesses: I. Chan
T. Ladanyi

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

Item No.		Col. 1 2007 Actual	Col. 2 2007 Board Approved Budget	Col. 3 2007 Actual Over (Under) Approved Budget (1-2)	Col. 4 2007* Adjustments	Col. 5 2007 Actual Over (Under) Approved Budget with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	2 872.9	2 763.1	109.8	88.0	21.8
1.1.2	Rate 1 - T-Service	1 818.2	1 723.0	95.2	53.7	41.5
1.1	Total Rate 1	4 691.1	4 486.1	205.0	141.7	63.3
1.2.1	Rate 6 - Sales	1 644.3	1 446.4	197.9	56.7	141.2
1.2.2	Rate 6 - T-Service	1 976.8	1 702.3	274.5	78.5	196.0
1.2	Total Rate 6	3 621.1	3 148.7	472.4	135.2	337.2
1.3.1	Rate 9 - Sales	2.0	5.4	(3.4)	0.0	(3.4)
1.3.2	Rate 9 - T-Service	0.6	2.0	(1.4)	0.0	(1.4)
1.3	Total Rate 9	2.6	7.4	(4.8)	0.0	(4.8)
1.	Total General Service Sales & T-Service	8 314.8	7 642.2	672.6	276.9	395.7
Contract Sales						
2.1	Rate 100	141.8	218.7	(76.9)	1.6	(78.5)
2.2	Rate 110	30.2	50.0	(19.8)	0.0 **	(19.8)
2.3	Rate 115	43.1	41.7	1.4	(0.1)	1.5
2.4	Rate 135	3.2	5.2	(2.0)	0.0 **	(2.0)
2.5	Rate 145	23.6	41.3	(17.7)	0.1	(17.8)
2.6	Rate 170	63.6	57.5	6.1	0.0 **	6.1
2.7	Rate 200	174.1	150.7	23.4	2.3	21.1
2.	Total Contract Sales	479.6	565.1	(85.5)	3.9	(89.4)
Contract T-Service						
3.1	Rate 100	899.4	1 169.9	(270.5)	13.6	(284.1)
3.2	Rate 110	577.8	570.4	7.4	(0.9)	8.3
3.3	Rate 115	851.6	864.5	(12.9)	(0.2)	(12.7)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	53.2	50.2	3.0	(0.1)	3.1
3.6	Rate 145	208.5	210.5	(2.0)	1.2	(3.2)
3.7	Rate 170	654.7	672.5	(17.8)	1.2	(19.0)
3.8	Rate 300	33.7	0.0	33.7	0.0	33.7
3.9	Rate 305	0.0	31.2	(31.2) ***	0.0	(31.2)
3.10	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	3 278.9	3 569.2	(290.3)	14.8	(305.1)
4.	Total Contract Sales & T-Service	3 758.5	4 134.3	(375.8)	18.7	(394.5)
5.	Total	12 073.3	11 776.5	296.8	295.6	1.2

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

** Less than 50,000 m^3.

*** Rate 305 is no longer a valid rate class effective January 1, 2007 after the implementation of NGEIR.

Witnesses: I. Chan
T. Ladanyi

The principal reasons for the variances contributing to the weather normalized increase of 1.2 10^6m^3 in the 2007 Actual over the 2007 Board Approved Budget are as follows:

1. The volumetric increase of 63.3 10^6m^3 in Rate 1 is due to higher average use per customer totalling 66.2 10^6m^3; partially offset by customers shortfall of 2.9 10^6m^3;

2. The volumetric increase of 337.2 10^6m^3 in Rate 6 is due to favourable customer variance of 7.6 10^6m^3, net customer migration from Contract Sales and T-Service of 333.0 10^6m^3; partially offset by a lower average use per customer totalling 3.4 10^6m^3;

3. The volumetric decrease of 4.8 10^6m^3 in Rate 9 is due to a lower average use per station totalling 4.6 10^6m^3 and a loss of two stations of 0.2 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 394.5 10^6m^3 is due to decreases in the apartment sector of 209.3 10^6m^3, the commercial sector of 93.8 10^6m^3, and the industrial sector of 112.5 10^6m^3 ; partially offset by increase of the Rate 200 of 21.1 10^6m^3. The decrease is attributable to net customer migration to General Service of 333.0 10^6m^3 as stated above as well as customers migrating from bundled rate classes to unbundled rate classes of 3.9 10^6m^3 in consequence of the implementation of NGEIR.

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	2,681	2,647	34	1.3%
		Rate 6	24,310	24,204	106	0.4%
		Total General Service	4,490	4,449	41	0.9%
	2009	Rate 1		2,637		
		Rate 6		28,165		
		Total General Service		4,770		

* 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.

**2008 Bridge Year Estimate was reported at column 1 because actual numbers are not available

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

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

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

CONTRACT MARKET CUSTOMERS NORMALIZED CONSUMPTION

	Test Year	Col. 1 Actual Normalized Consumption (m^3)	Col. 2 Board Approved Normalized Consumption (m^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**	3,203.0	3,355.2	(152.2)	-4.5%
	2009		2,316.6		

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

**2008 Bridge Year Estimate was reported at column 1 because actual numbers are not available

CUSTOMERS BUDGET

1. The purpose of this exhibit is to present the calculation of the 2009 annual average customers reported in the 2009 Revenue per Customer Cap formula at Exhibit B, Tab 1, Schedule 2. The annual average customer numbers calculation methodology used by the Company has been applied to calculate Board Approved annual average customer numbers for more than ten years. All the information shown in this evidence is on a calendar-year billing-period basis (i.e., on a December fiscal year end basis) excluding the Historical Actual vs. Board Approved section. The Test Year Budget includes calendar 2007 actual and 2008 bridge estimate billing information.

2. The total customer additions for the 2009 Budget are 41,241 and the forecast is described in detail in the evidence at Exhibit B, Tab 1, Schedule 4. These forecast customer additions correspond to an increase of 41,433 in the average number of customers as shown in Exhibit B, Tab 1, Schedule 5, Appendix A, page 2. This forecast underpins the new customer volumes of 112.5 $10^6 m^3$ added between 2009 Budget and 2008 Estimate at Exhibit B, Tab 1, Schedule 5, Page 5.

3. Consistent with previous rate proceedings, each year's customer numbers are reported on an annual average of monthly customer numbers. Every month customer numbers are measured by number of active meters (or known as unlock meters)[1] among the Company's customers that use gas. As a result, each month's customer number is an aggregate sum of the total active meters for that particular month. Specifically, each year's annual average is calculated as follows:

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

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 at Exhibit B, Tab 1, Schedule 5, page 23, 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 (2008 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 (2008 Estimate)
*+ forecast new construction customer additions*new construction time lag*
*+ forecast replacement customer additions*replacement time lag*
+ historical average monthly change in actual lock customers
+ forecast transfer gains (i.e. customer migration from contract market rate class to general service Rate 6)
- forecast transfer losses (i.e. customer migration from general service Rate 6 to contract market rate class)

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

Table 1 - Historical Annual Average of Lock Customers

Calendar Year	Lock Customers
2005	29,266
2006	31,951
2007	33,240

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

8. Similar to lock customers, this time lag is also random and unsystematic as it is difficult to predict customer’s behaviour, such as when customer moves into the premise or when the premise is sold. Therefore, the latest available historical actual data is used in order to obtain an objective forecast of lock meters for the budget. Table 2 below presents a summary of the 2009 budgeted time lag. It is expected that all else being equal, 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 - 2009 Budget Time Lag (i.e. Number of Months)

Sector	New Construction	Replacement	
Residential	6	3	
Apartment	3	3	*
Commercial	16	15	
Industrial	3	3	*

Note:
*As a result of lacking sufficient data for these two sectors because these sectors usually have few customer additions, the data reported for these sectors have not been updated with the latest actual and are based upon information that has been used for more than ten years

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

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

10. Table 3 on the next page, illustrates 13-Year of Historical Actual vs. Board Approved customer numbers. Overall, the average percentage error variances over the past 13 years were only 0.2% or 2,105 customers. Overall, the existing methodology has continued to be a good predictor of actual customers.

TABLE 3 - GENERAL SERVICE AND CONTRACT MARKET CUSTOMERS

	Test Year	Col. 1 Actual Customers	Col. 2 Board Approved Customers	Col. 3 Variance Customers (1-2)	Col. 4 %Variance Customers (3/2)*100
FISCAL YEAR	1995	1,222,293	1,216,511	5,782	0.5%
	1996	1,263,290	1,262,815	475	0.0%
	1997	1,312,434	1,309,752	2,682	0.2%
	1998	1,364,350	1,353,178	11,172	0.8%
	1999	1,414,788	1,417,832	(3,044)	-0.2%
	2000[a]	1,464,738	1,468,915	(4,177)	-0.3%
	2001	1,519,039	1,514,710	4,329	0.3%
	2002	1,566,710	1,565,017	1,693	0.1%
	2003	1,622,016	1,615,037	6,979	0.4%
	2004*	1,676,380	1,672,586	3,794	0.2%
	2005[b]	1,724,716	1,718,766	5,950	0.3%
CALENDAR YEAR	2006	1,782,813	1,792,615	(9,802)	-0.5%
	2007	1,824,789	1,823,258	1,531	0.1%
	2008**	1,865,004	1,864,047	957	0.1%
	2009		1,906,437		

* 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.

**2008 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.

Y FACTOR POWER GENERATION PROJECTS

1. The Company has two Power Generation Projects budgeted for 2009. Table 1 summarizes capital expenditure and other project details. In recent history, Portlands Energy Centre and Thorold Cogen were awarded contracts by the Ontario Power Authority. These facilities are natural gas fired and are located within the Enbridge's franchise area.

2. In 2009 the Company will finalize the Portlands Energy Centre Pipeline project. A budget of $1.576 M has been set for restoration and project completion.

3. On August 15th 2007 Enbridge signed a Rate 125 gas delivery agreement with Thorold Cogen. A Leave to Construct application was filed with the Board on June 27, 2008. The project is currently in the pre-engineering phase. Pending Board approval, construction is slated for summer of 2009 with gas delivery beginning in September.

4. A revenue requirement determination in relation to these projects can be found in Appendix A of this Exhibit.

Table 1
Summary of 2009 Power Generation Related Projects

Facility	Portlands Energy Centre	Thorold Cogen Pipeline
Location	Toronto	Thorold
Proposed Completion Date	Fall 2008	Fall 2009
Pipe Size and Length	NPS 20, 2.9 km NPS 36, 6.5 km	NPS 12, 3 km
2009 Budget	$1.576 M	$5.794 M
Total Forecast Budget	$24.259 M	$6.394 M

Witnesses: K. Culbert
T. Ladanyi
T. Tuck

Ontario Utility 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
7.	Ontario Utility Income	(67.4)	(201.3)
8.	Rate base	8,909.9	25,800.4
9.	Indicated rate of return	(0.76)%	(0.78)%
10.	(Def.) / suff. in rate of return	(8.34)%	(8.36)%
11.	Net (def.) / suff.	(743.1)	(2,156.9)
12.	Gross (def.) / suff.	(1,117.4)	(3,219.3)

Ontario Utility Rate Base
Power Generation Y-Factor Calculation

($000's)

Line No.		2008	2009
	Property, plant, and equipment		
1.	Cost or redetermined value	9,018.0	26,676.8
2.	Accumulated depreciation	(108.1)	(876.4)
3.		8,909.9	25,800.4
	Allowance for working capital		
4.	Accounts receivable merchandise finance plan	-	-
5.	Accounts receivable rebillable projects	-	-
6.	Materials and supplies	-	-
7.	Mortgages receivable	-	-
8.	Customer security deposits	-	-
9.	Prepaid expenses	-	-
10.	Gas in storage	-	-
11.	Working cash allowance	-	-
12.		-	-
13.	Ontario utility rate base	8,909.9	25,800.4

Ontario Utility Income
Power Generation Y-Factor Calculation

($000's)

Line No.		2008	2009
	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	385.8	1,048.3
10.	Municipal and other taxes	62.7	63.9
11.	Total costs and expenses	448.5	1,112.2
12.	**Utility income before inc. taxes**	(448.5)	(1,112.2)
	Income taxes		
13.	Excluding interest shield	(248.9)	(533.7)
14.	Tax shield on interest expense	(132.2)	(377.2)
15.	Total income taxes	(381.1)	(910.9)
16.	**Ontario utility net income**	(67.4)	(201.3)

Ontario Utility Taxable Income and Income Tax Expense
Power Generation Y-Factor Calculation

($000's)

Line No.		2008	2009
1.	Utility income before income taxes	(448.5)	(1,112.2)
	Add Backs		
2.	Depreciation and amortization	385.8	1,048.3
3.	Large corporation tax	-	-
4.	Other non-deductible items	-	-
5.	Any other add back(s)	-	-
6.	Total added back	385.8	1,048.3
7.	Sub total - pre-tax income plus add backs	(62.7)	(63.9)
	Deductions		
8.	Capital cost allowance - Federal	680.5	1,553.3
9.	Capital cost allowance - Provincial	680.5	1,553.3
10.	Items capitalized for regulatory purposes	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-
12.	Amortization of share and debt issue expense	-	-
13.	Amortization of cumulative eligible capital	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-
15.	Any other deduction(s)	-	-
16.	Total Deductions - Federal	680.5	1,553.3
17.	Total Deductions - Provincial	680.5	1,553.3
18.	Taxable income - Federal	(743.2)	(1,617.2)
19.	Taxable income - Provincial	(743.2)	(1,617.2)
20.	Income tax provision - Federal	(144.9)	(307.3)
21.	Income tax provision - Provincial	(104.0)	(226.4)
22.	Income tax provision - combined	(248.9)	(533.7)
23.	Part V1.1 tax	-	-
24.	Investment tax credit	-	-
25.	Total taxes excluding tax shield on interest expense	(248.9)	(533.7)
	Tax shield on interest expense		
26.	Rate base as adjusted	8,909.9	25,800.4
27.	Return component of debt	4.43%	4.43%
28.	Interest expense	394.7	1,143.0
29.	Combined tax rate	33.500%	33.000%
30.	Income tax credit	(132.2)	(377.2)
31.	**Total income taxes**	(381.1)	(910.9)

Ontario Utility Revenue Requirement
Power Generation Y-Factor Calculation

($000's)

Line No.		2008	2009
	Cost of capital		
1.	Rate base	8,909.9	25,800.4
2.	Required rate of return	7.58%	7.58%
3.	Cost of capital	675.4	1,955.7
	Cost of service		
4.	Gas costs	-	-
5.	Operation and Maintenance	-	-
6.	Depreciation and amortization	385.8	1,048.3
7.	Municipal and other taxes	62.7	63.9
8.	Cost of service	448.5	1,112.2
	Misc. & Non-Op. Rev		
9.	Other operating revenue	-	-
10.	Other income	-	-
11.	Misc, & Non-operating Rev.	-	-
	Income taxes on earnings		
12.	Excluding tax shield	(248.9)	(533.7)
13.	Tax shield provided by interest expense	(132.2)	(377.2)
14.	Income taxes on earnings	(381.1)	(910.9)
	Taxes on (def) / suff.		
15.	Gross (def.) / suff.	(1,117.4)	(3,219.3)
16.	Net (def.) / suff.	(743.1)	(2,156.9)
17.	Taxes on (def.) / suff.	374.3	1,062.4
18.	**Revenue requirement**	1,117.1	3,219.4
	Revenue at existing Rates		
19.	Gas sales	0.0	0.0
20.	Transportation service	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0
22.	Rounding adjustment	(0.3)	0.1
23.	Revenue at existing rates	(0.3)	0.1
24.	**Gross revenue (def.) / suff.**	(1,117.4)	(3,219.3)

Y FACTORS - OTHER

1. This evidence supports the Company's adjustments in relation to Y-factors other than the capital related power generation Y-factor. Capital related power generation Y-factor evidence is filed at Exhibit B, Tab 1, Schedule 6. The incentive regulation formula adjustments for the other Y-factor elements are found within the revenue per customer cap formula evidence, Exhibit B, Tab 1, Schedule 2, page 1.

2. The Company, as approved by the Board in the EB-2007-0615 proceeding, is required to adjust its revenue requirement determined by the revenue per customer cap formula for the incremental change in the cost(s) to be recovered in rates related to:

   a. DSM program costs which were approved by the Board in its EB-2006-0021 proceeding for the years 2007 through 2009, as well as any subsequent Natural Gas Generic DSM proceedings and/or Board Decision(s) related to DSM program costs (Ref. Exhibit E-3-1);

   b. CIS / Customer Care costs that result from the application of the 'True Up Template' approved by the Board in the 2008 Final Rate Order, EB-2007-0615, Appendix F, page 1 (Ref. Exhibit E-2-1); and

   c. Incremental gas costs associated with upstream transportation, storage and supply mix costs relative to the Company's 2009 volumetric forecast. The Company's forecast of gas cost to operations for 2009 at this time is found at Exhibit B, Tab 5, Schedules 1 & 2. Additionally, an adjustment is required to allow for the change in approved rates related to the embedded carrying cost of gas in storage and working cash related to gas costs. That is, an adjustment is required to remove the costs associated with the previously approved recovery

of the 2008 costs from rates and replace them with the costs associated with the 2009 forecast carrying cost 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 the details of this calculation.

Z FACTORS

1. The Company's is not proposing to recover any Z Factor(s) in this, its 2009 rate adjustment application.

2. The Company is applying for the Board's approval to establish a deferral account in its 2009 fiscal year in which it can record the incremental costs associated with the requirement for the Company to be compliant with the implementation of International Financial Reporting Standards ("IFRS") within the established timelines for IFRS. The evidence requesting the IFRSDA can be found at Exhibit C, Tab 1, Schedule 2. The manner in which the future recovery should be handled will be brought forward by the Company in a future proceeding.

Witness: R. Bourke

RATE HANDBOOK

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

INDEX

PART I:	GLOSSARY OF TERMS	Page 1
PART II:	RATES AND SERVICES AVAILABLE	Page 3
PART III:	TERMS AND CONDITIONS - APPLICABLE TO ALL SERVICES	Page 5
PART IV:	TERMS AND CONDITIONS - DIRECT PURCHASE ARRANGEMENTS	Page 7
PART V:	RATE SCHEDULES	Page 9

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: A contract clause intended to excuse one or more parties from their obligations under a contract, in situations where performance is frustrated by unusual or severe circumstances beyond their control such as flood, fire, war, or prolonged labour strike.

Gas: Natural Gas.

Gas Delivery Agreement: A written agreement pursuant to which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Gas Distribution Network: The physical facilities owned by the Company and utilized to contain, move and measure natural gas.

Gas Sale Contract: A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Gas Supply Charge: A charge for the gas commodity purchased by the applicant.

Gas Supply Load Balancing Charge: A charge in the Rate Schedules where the Company recovers the cost of ensuring gas supply matches consumption on a daily basis.

General Service Rates: The Rate Schedules applicable to those Bundled Services for which a specific contract between the Company and the Applicant is not generally required. The General Service Rates include Rates 1, 6, and 9 of the Company.

Gigajoule ("GJ"): See Joule.

Hourly Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule which is the maximum volume of gas the Company is required to deliver to an Applicant on a hourly basis under a Service Contract.

Imperial Conversion Factors:

Volume:

1,000 cubic feet (cf)	=	1 Mcf
	=	28.32784 cubic metres (m^3)
1 billion cubic feet (cf)	=	28.32784 $10^6 m^3$

Pressure:

1 pound force per square inch (p.s.i.)	=	6.894757 kilopascals (kPa)
1 inch Water Column (in W.C.) (60°F)		
	=	0.249 kPa (15.5°C)
1 standard atmosphere	=	101.325 kPa

Energy:

1 million British thermal units	=	1 MMBtu
	=	1.055056 gigajoules (GJ)
948,213.3 Btu	=	1 GJ

Monetary Value:

$1 per Mcf	=	$0.03530096 per m^3
$1 per MMBtu	=	$0.9482133 per GJ

Interruptible Service: Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the Company.

Intra-Alberta Service: Firm transportation service on the Nova pipeline system under which volumes are delivered to an Intra-Alberta point of acceptance.

Joule ("J"): The amount of work done when the point of application of a force of one newton is displaced a distance of one metre in the direction of the force. One megajoule ("MJ") means 1,000,000 joules; one gigajoule ("GJ") means 1,000,000,000 joules.

Large Volume Distribution Contract: (LVDC): A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Large Volume Distribution Contract Rates: The Rate Schedules applicable for annual consumption exceeding 340,000 cubic metres of gas per year and for which a specific contract between the Company and the Applicant is required.

Load-Balancing: The balancing of the gas supply to meet demand. Storage and other peak supply sources, curtailment of interruptible services, and diversions from one delivery point to another may be used by the Company.

Make-up Volume: A volume of gas nominated and delivered, pursuant to mutually agreed arrangements, by an Applicant to the Company for the purpose of reducing or eliminating a net debit balance in the Applicant's Banked Gas Account.

Mean Daily Volume (MDV): The volume of gas which an Applicant who delivers gas to the Company, under a T-Service arrangement, agrees to deliver to the Company each day in the term of the arrangement.

Metric Conversion Factors:

Volume:

1 cubic metre (m^3)	=	35.30096 cubic feet (cf)
1,000 cubic metres	=	10^3m^3
	=	35,300.96 cf
	=	35.30096 Mcf
28.32784 m^3	=	1 Mcf

Pressure:

1 kilopascal (kPa)	=	1,000 pascals
	=	0.145 pounds per square inch (p.s.i.)
101.325 kPa	=	one standard atmosphere

Energy:

1 megajoule (MJ)	=	1,000,000 joules
	=	948.2133 British thermal units (Btu)
1 gigajoule (GJ)	=	948,213.3 Btu
1.055056 GJ	=	1 MMBtu

Monetary Value:

\$1 per 10^3m^3	=	\$0.02832784 per Mcf
\$1 per gigajoule	=	\$1.055056 per MMBtu

Minimum Annual Volume: The minimum annual volume as stated in the customer's contract, also Section E.

Natural Gas: Natural and/or residue gas comprised primarily of methane.

Nominated Volume: The volume of gas which an Applicant has advised the Company it will deliver to the Company in a day.

Nominate, Nomination: The procedure of advising the Company of the volume which the Applicant expects to deliver to the Company in a day.

Ontario Energy Board: An agency of the Ontario Government which, amongst other things, approves the Company's Rate Schedules (Part V of this HANDBOOK) and the matters described in Parts III and IV of this HANDBOOK.

Point of Acceptance: The point at which the Company accepts delivery of a supply of natural gas for transportation to, or purchase from, the Applicant.

Rate Schedule: A numbered rate of the Company as fixed or approved by the OEB. that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

Seasonal Credit: A credit applicable to Rate 135 customers to recognize the benefits they provide to the storage operations during the winter period.

Service Contract: An agreement between the Company and the Applicant which describes the responsibilities of each party in respect to the arrangements for the Company to provide Sales Service or Transportation Service to one or more Terminal Locations.

System Sales Service: A service of the Company in which the Company acquires and sells to the Applicant the Applicant's natural gas requirements.

T-Service: Transportation Service.

Terminal Location: The building or other facility of the Applicant at or in which natural gas will be used by the Applicant.

Transportation Service: A service in which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Unbundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Applicant contracting for separate services (upstream transportation, load balancing/storage, transportation on the Company's distribution system) of which only Transportation Service is mandatory with the Company.

Western Canada Buy Price: The price per cubic metre which the Company would pay for gas pursuant to a Buy/Sell Agreement in which the purchase takes place in Western Canada.

PART II

RATES AND SERVICES AVAILABLE

The provisions of this PART II are intended to provide a general description of services offered by the Company and certain matters relating thereto. Such provisions are not definitive or comprehensive as to their subject matter and may be changed by the Company at any time without notice.

SECTION A - INTRODUCTION

1. In Franchise Services

Enbridge Gas Distribution provides in franchise services for the transportation of natural gas from the point of its delivery to Enbridge Gas Distribution to the Terminal Location at which the gas will be used. The natural gas to be transported may be owned by the Applicant for service or by the Company. In the latter case, it will be sold to the customer at the outlet of the meter located at the Terminal Location.

Applicants may elect to have the Company provide all-inclusively the services which are mutually agreed to be required or they may

select (from the 300 series of rates, and Rate 125) only the amounts of those services which they consider they need.

The all-inclusive services are provided pursuant to Rates 1, 6 and 9, ("the General Service Rates") and Rates 100, 110, 115, 135, 145, and 170 ("the Large Volume Service Rates"). Individual services are available under Rates 125, 300, 315, and 316 ("the Unbundled Service Rates").

Service to residential locations is provided pursuant to Rate 1.

Service which may be interrupted at the option of the Company is available, at rates lower than would apply for equivalent service under a firm rate schedule, pursuant to Rates 145, 170. Under all other rate schedules, service is provided upon demand by the Applicant, i.e., on a firm service basis.

2. Ex-Franchise Services

Enbridge Gas Distribution provides ex-franchise services for the transportation of natural gas through its distribution system to a point of interconnection with the distribution system of other distributors of natural gas. Such service is provided pursuant to Rate 200 and provides for the bundled transportation of gas owned by the Company, owned by customers of that distributor, or owned by that distributor.

For the purposes of interpreting the terms and conditions contained in this Handbook of Rates and Distribution Services the ex - franchise distributor shall be considered to be the applicant for the transportation of its customer owned gas and shall assume all the obligations of transportation as if it owned the gas.

Nominations for transportation service must specify whether the volume to be transported is to displace firm or interruptible demand or general service.

In addition, the Company provides Compression, Storage, and Transmission services on its Tecumseh system under Rates 325, 330 and 331.

SECTION B - DIRECT PURCHASE ARRANGEMENTS

Applicants who purchase their natural gas requirements directly from someone other than the Company or who are brokers or agents for an end user, may arrange to transport gas on the Company's distribution network in conjunction with a Western Buy/Sell Arrangement or pursuant to an Ontario Delivery Transportation Service Arrangement, whether Bundled or Unbundled, or a Western Bundled Transportation Service Arrangement.

B. Western Canada

Buy/Sell in a Western Canada Buy/Sell Arrangement the Applicant delivers gas to a point in Western Canada which connects with the transmission pipeline of TransCanada PipeLines Limited. At that point, the Company purchases the gas from the Applicant at a price specified in Rider 'B' of the rate schedules less the costs for transmission of the gas from the point of purchase to a point in Ontario at which the Company's gas distribution network connects with a transmission pipeline system. The Company will not be entering into any new Western Canada buy/sell arrangements after April 1, 1999.

C. Ontario Delivery T-Service Arrangements

In an Ontario Delivery T-Service Arrangement the Applicant delivers gas, to a contractually agreed-upon point of acceptance in Ontario.

Delivery from the point of direct interconnection with the Company's gas distribution network to a Terminal Location served from the Company's gas distribution network may be obtained by the Applicant either under the Bundled Service Rate Schedules or under the Unbundled Service Rate Schedules.

(i) Bundled T-Service

Bundled T-Service is so called because all of the services required by the Applicant (delivery and load balancing) are provided for the prices specified in the applicable Rate Schedule. In a Bundled T-Service arrangement the Applicant contracts to deliver each day to the Company a Mean Daily Volume of gas. Fluctuations in the demand for gas at the Terminal Location are balanced by the Company.

(ii) Unbundled T-Service

The Unbundled Service Rates allow an Applicant to contract for only such kinds of service as the Applicant chooses. The potential advantage to an Applicant is that the chosen amounts of service may be less than the amounts required by an average customer represented in the applicable Rate Schedule, in which case the Applicant may be able to reduce the costs otherwise payable under Bundled T-Service.

D. Western Delivery T-Service Arrangement

In a Western Delivery T-Service Arrangement the Applicant contracts to deliver each day to a point on the TransCanada PipeLines Ltd. transmission system in Western Canada a Mean Daily Volume of gas plus fuel gas. Delivery from that point to the Terminal Location is carried out by the Company using its contracted capacity on the TransCanada PipeLines Limited. system and its gas distribution network. Unbundled T-Service in Ontario is not available with the Western Delivery Option.

An Applicant desiring to receive Transportation Service or to establish a Buy/Sell Agreement must first enter into the applicable written agreements with the Company.

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% 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 Baked gas Account.

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

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

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

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

plus

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

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

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

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

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

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.

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

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 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 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 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.

(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 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 average Ontario Transportation Service Credit over the contract year. 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 T-Service:

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

RATE NUMBER: 1	RESIDENTIAL SERVICE

APPLICABILITY:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$16.00**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**14.4869 ¢/m³**
For the next 55 m³ per month	**13.9273 ¢/m³**
For the next 85 m³ per month	**13.4887 ¢/m³**
For all over 170 m³ per month	**13.1621 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.7802 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 6	GENERAL SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") for non-residential purposes.

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$55.00**
Delivery Charge per cubic metre	
For the first 500 m³ per month	**13.3159 ¢/m³**
For the next 1050 m³ per month	**11.5362 ¢/m³**
For the next 4500 m³ per month	**10.2904 ¢/m³**
For the next 7000 m³ per month	**9.4896 ¢/m³**
For the next 15250 m³ per month	**9.1337 ¢/m³**
For all over 28300 m³ per month	**9.0447 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.8980 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 9	CONTAINER SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") at which, such gas is authorized by the Company to be resold by filling pressurized containers.

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$232.64**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**15.4501 ¢/m³**
For all over 20,000 m³ per month	**14.7744 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 100	FIRM CONTRACT 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 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	**$121.23**
Delivery Charge	
Per cubic metre of Contract Demand	**8.1900 ¢/m³**
For the first 14,000 m³ per month	**5.1517 ¢/m³**
For the next 28,000 m³ per month	**3.7927 ¢/m³**
For all over 42,000 m³ per month	**3.2337 ¢/m³**
Gas Supply Load Balancing Charge	**5.5402 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.7362 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

RATE NUMBER: **100**

MINIMUM BILL:

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

10.6117 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

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	**$583.61**
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	**0.5529 ¢/m³**
For all over 1,000,000 m³ per month	**0.4029 ¢/m³**
Gas Supply Load Balancing Charge	**5.0683 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

RATE NUMBER: **110**

MINIMUM BILL:

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

5.5410 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 115	LARGE VOLUME LOAD FACTOR SERVICE

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$619.67**
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	**0.2940 ¢/m³**
For all over 1,000,000 m³ per month	**0.1940 ¢/m³**
Gas Supply Load Balancing Charge	**4.9335 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

RATE NUMBER: **115**

MINIMUM BILL:

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

5.1473 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 125	EXTRA LARGE FIRM DISTRIBUTION SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("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 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	**9.0093 ¢/m³**
Direct Purchase Administration Charge	**$50.00**
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). 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).

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 (also referred to as Banked Gas Account):

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 = 0.9004 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 1.0805 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.

The customers shall also pay any Load 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 title transfer gas from their Cumulative Imbalances Account (Banked Gas Account) into a Rate 316 storage account of the customer provided that the customer has space available in the storage account to accommodate the transfer.

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 cannot title transfer gas from their Cumulative Imbalances Account (Banked Gas Account) in whole or in part to storage the Company shall deem the excess imbalance to be Unauthorized Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee shall be equal to 1.0343 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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

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	**$114.54**	**$114.54**
Delivery Charge		
For the first 14,000 m³ per month	**6.7025 ¢/m³**	**2.0025 ¢/m³**
For the next 28,000 m³ per month	**5.5025 ¢/m³**	**1.3025 ¢/m³**
For all over 42,000 m³ per month	**5.1025 ¢/m³**	**1.1025 ¢/m³**
Gas Supply Load Balancing Charge	**4.8874 ¢/m³**	**4.8874 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.7057 ¢/m³**	**33.7057 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

Failure to deliver a volume of gas equal to the Mean Daily Volunder 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	**$**	**0.77 /m^3**
Rate per cubic metre of Modified Mean Daily Volume for December	**$**	**0.77 /m^3**

SEASONAL OVERRUN CHARGE:

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

Seasonal Overrun Charges:

December and March	**23.1798 ¢/m³**
January and February	**57.9495 ¢/m³**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**8.3764 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 145	INTERRUPTIBLE SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service as ordered by the Company exercising its sole discretion. Any Applicant for service under this rate schedule must agree to transport a minimum annual volume of 340,000 cubic metres.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 72 hours prior to the time at which such curtailment or discontinuance is to commence. An Applicant may, by contract, agree to accept a shorter notice period.

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$122.53**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.8881 ¢/m³**
For the next 28,000 m³ per month	**1.5291 ¢/m³**
For all over 42,000 m³ per month	**0.9701 ¢/m³**
Gas Supply Load Balancing Charge	**5.3934 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.7875 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

Rate for 16 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.50**	**/m³**
Rate for 72 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.11**	**/m³**

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

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations. For any location presently served or any new Applicant for service pursuant to this Rate Schedule in these areas, the Company shall purchase the rights to take service hereunder at 1.25 ¢/m³ per unit of Daily Capacity Repurchase Quantity.

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **8.2014 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 170	LARGE INTERRUPTIBLE SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas of not less than 30,000 cubic metres and a minimum annual volume of 5,000,000 cubic metres to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service when required by the Company. The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$277.09**
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	**0.5299 ¢/m³**
For all over 1,000,000 m³ per month	**0.3299 ¢/m³**
Gas Supply Load Balancing Charge	**5.1572 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/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. For any location presently served or any new Applicant for service pursuant to this Rate Schedule in these areas, the Company shall purchase the rights to take service hereunder at 1.25 ¢/m³ per unit of Daily Capacity Repurchase Quantity.

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

MINIMUM BILL:

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

5.6069 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: **200**	**WHOLESALE SERVICE**

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	**1.1359 ¢/m³**
Gas Supply Load Balancing Charge	**5.6049 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**33.5855 ¢/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. For any location presently served or any new Applicant for service pursuant to this Rate Schedule in these areas, the Company shall purchase the rights to take service hereunder at 1.25 ¢/m³ per unit of Daily Capacity Repurchase Quantity.

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **6.6606 ¢/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, 2009 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the numbered rate schedule that specifies as the effective date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 300	FIRM OR INTERRUPTIBLE DISTRIBUTION SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation to a single Terminal Location of a specified maximum daily volume of natural gas. The Company reserves the right to limit service under this schedule to customers whose maximum contract demand does not exceed 600,000 m3. The Service under this rate requires Automatic Meter Reading (AMR) capability. Service under this schedule is firm unless a customer is currently served under interruptible distribution service or the Company, in its sole judgment, determines that existing delivery facilities cannot adequately serve the load on a firm basis.

The unitized Monthly Contract Demand Charge is also applicable to volumes delivered to any Applicant taking service under a Curtailment Delivered Supply contract with the Company. The unitized rate equals the applicable Monthly Contract Demand Charge times 12/365.

CHARACTER OF SERVICE:

The Service shall be continuous (firm) except for events specified in the Service Contract including force majeure. The Applicant is neither allowed to take a daily quantity of gas greater than the Contract Demand nor an hourly amount in excess of the Contract Demand divided by 24, without the Company's prior consent. Interruptible Distribution Service is provided on a best efforts basis subject to the events identified in the service contract including force majeure and, in addition, shall be subject to curtailment or discontinuance of service when the Company notifies the customer under normal circumstances 4 hours prior to the time that service is subject to curtailment or discontinuance. Under emergency conditions, the Company may curtail or discontinue service on one-hour notice. The Interruptible Service Customer is not allowed to exceed maximum hourly flow requirements as specified in Service Contract.

DISTRIBUTION RATES:

Monthly Customer Charge	**$500.00**
Monthly Contract Demand Charge Firm	**24.7336 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3554 ¢/m³**
Maximum Delivery Charge	**0.9758 ¢/m³**
Direct Purchase Administration Charge	**$50.00**
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). 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).

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 (also referred to as Banked Gas Account):

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 0.9004 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 1.0805 cents/m3

The customers shall also pay any Load 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 Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee shall be equal to of 0.5738 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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 315	GAS STORAGE SERVICE

APPLICABILITY:

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

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

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

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

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

CHARACTER OF SERVICE:

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

The service is available on two bases:

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

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

RATE:

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

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0466 ¢/m³**
Monthly Storage Deliverability/Injection Demand Charge	**13.6672 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.5136 ¢/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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies effective date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263.

RATE NUMBER: 316	GAS STORAGE SERVICE AT DAWN

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, which may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA).

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	**0.0466 ¢/m³**
Monthly Storage Deliverability/Injection Demand Charge	**4.3168 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.1672 ¢/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.

RATE NUMBER: **316**

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 TransCanad 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, which may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA).

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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies effective date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263.

BACKSTOPPING SERVICE

APPLICABILITY:

To any Applicant whose delivery of natural gas to the Company for transportation to a Terminal Location has been interrupted prior to the delivery of such gas to the Company.

CHARACTER OF SERVICE:

The volume of gas available for backstopping in any day shall be determined by the Company exercising its sole discretion. If the aggregate daily demand for service under this Rate Schedule exceeds the supply available for such day, the available supply shall be allocated to firm service customers on a first requested basis and any balance shall be available to interruptible customers on a first requested basis.

RATE:

The rates applicable in the circumstances contemplated by this Rate Schedule, in lieu of the Gas Supply Charges specified in any of the Company's other Rate Schedules pursuant to which the Applicant is taking service, shall be as follows:

	Billing Month January to December
Gas Supply Charge	
Per cubic metre of gas sold	**39.0903 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

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 $/10³m³	**Pool Storage $/10³m³**
Demand Charge for:		
Annual Turnover Volume	**0.1838**	**0.2185**
Maximum Daily Withdrawal Volume	**16.6188**	**19.8179**
Commodity Charge	**1.5051**	**0.5898**

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	**2.4264**	**0.5464**
Unauthorized	**-**	**219.3685**
Pool Storage		
Authorized	**2.8840**	**0.6515**
Unauthorized	**-**	**261.5969**

(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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

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	
	$/10³m³	$/10³m³	$/10³m³
Monthly Demand Charge per unit of Annual Turnover Volume:			
Minimum	**0.4023**	**0.4023**	**-**
Maximum	**2.0115**	**2.0115**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**36.4368**	**29.1494**	**-**
Maximum	**182.1839**	**145.7471**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**2.0949**	**2.0949**	**0.9219**
Maximum	**10.4745**	**10.4745**	**41.6932**

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	Interruptible	
	$/10³m³	$/10³m³	$/10³m³
Authorized Overrun Annual Turnover Volume Negotiable, not to exceed:	**41.6932**	**41.6932**	**41.6932**
Authorized Overrun Daily Injection/Withdrawal Negotiable, not to exceed:	**41.6932**	**41.6932**	**41.6932**
Unauthorized Overrun Annual Turnover Volume Excess Storage Balance			
September 1 - November 30	**416.9320**	**416.9320**	**416.9320**
December 1 - October 31	**41.6932**	**41.6932**	**41.6932**
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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

APPLICABILITY:

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

CHARACTER OF SERVICE:

Service under this rate is for firm transportation service as may be available from time to time.

RATE:

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

	Firm $/10^3m^3$	Interruptible $/10^3m^3$
Monthly Demand Charge per unit of Maximum Contracted Daily Delivery:	**5.1620**	**-**
Commodity Charge per unit of gas delivered:	**-**	**0.2040**

MINIMUM BILL:

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

TERMS AND CONDITIONS OF SERVICE:

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

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

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

AREAS OF CAPACITY CONSTRAINT

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:

Base Charge	$50.00 per month
Maximum Charge	$815.00 per month
Account Charge	
New Accounts	$0.50 per month per account
Renewal Accounts	$0.15 per month per account

The above Basic Charge shall be increased up to the maximum charge, by the new account charge for each new account and by the Renewal Account charge for each renewal account in a Direct Purchase Contract.

T-SERVICE CREDIT:

In T-Service Arrangements excluding Ontario ABC-T arrangements, between the Company and an Applicant, and with a T-Service Arrangement and a contractually specified Point of Acceptance as indicated below, the Company shall pay or charge the Applicant the Transportation Service Credit or Debit shown for any volumes of natural gas owned by the Applicant and received by the Company at the Point of Acceptance. The ability of the Company to accept deliveries under FT-type arrangements at Dawn is constrained and the availability of this service is at the Company's sole discretion.

TOLLS CREDIT	**Type of Arrangement**	
Point of Acceptance	Firm Transportation (FT)	Firm Service Tendered (FST)
Western Canada	0.0000 ¢/m³	0.0000 ¢/m³
CDA, EDA	4.8874 ¢/m³	0.0000 ¢/m³
Dawn	4.6406 ¢/m³	0.0000 ¢/m³
Intra-Alberta	-0.5514 ¢/m³	N/A

Effective February 1, 2001, in Ontario ABC-T arrangements with a contractually specified Point of Acceptance in the CDA and/or EDA, the toll credit shall equal the Eastern Zone Firm Transportation tolls approved by the National Energy Board for TCPL at a 100% load factor.

TCPL FT CAPACITY TURNBACK:

APPLICABILITY:

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

TERMS AND CONDITIONS OF SERVICE:

1. The Company will accommodate TCPL FT capacity turnback from customers to the extent that the Company is allowed to turnback FT capacity to TCPL.

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

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

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

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

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

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

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

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

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

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

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

    or

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

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

RIDER: B	BUY / SELL SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who entered into a Gas Purchase Agreement with the Company, prior to April 1, 1999, to sell to the Company a supply of natural gas.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Base Charge	$50.00	per month
Maximum Charge	$815.00	per month
Account Charge		
New Accounts	$0.50	per month per account
Renewal Accounts	$0.15	per month per account

The above Basic Charge shall be increased up to the maximum charge, by the new account charge for each new account and by the Renewal Account charge for each renewal account in a Direct Purchase Contract.

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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

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

RIDER: D	

EFFECTIVE DATE:	IMPLEMENTATION DATE:	BOARD ORDER:	REPLACING RATE EFFECTIVE:	Page 1 of 1
January 1, 2009	January 1, 2009	EB-2008-0219	October 1, 2008	Handbook 54

ENBRIDGE

RIDER: E	REVENUE ADJUSTMENT RIDER

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

RIDER: F	ATMOSPHERIC PRESSURE FACTORS

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

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

	Rate (excluding GST)
New Account Or Activation	
New Account Charge Turning on of gas, activating appliances, obtaining billing data and establishing an opening meter reading for new customers in premises where gas has been previously supplied	$25.00
Appliance Activation Charge - Commercial Customers Only Commercial customers are charged an appliance activation charge on unlock and red unlock orders, except on the very first unlock and service unlock at a premise.	$65.00 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	$65.00
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)	$65.00
Removal of Meter Removing meter by Construction & Maintenance crew	$260.00
Cut Off At Main Charge Cutting service off at main by Construction & Maintenance Crew	$1,200.00
Valve Lock Charge Shutting off service by closing the street shut-off valve - work performed by Field Investigator	$125.00
- work performed by Construction & Maintenance	$260.00

RIDER: **G**

Safety Inspection	
Inspection Not Ready Charge (safety inspection) When a builder requests an unlock and the appliance(s) are not ready for inspection, this charge will apply to cover the cost of returning to the same property for the additional inspection.	$65.00
Inspection Reject Charge (safety inspection) Energy Board Inspection rejects are billed to the meter installer or homeowner.	$65.00
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	$97.50
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	$130.00
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.	$1,200.00
Meter In-Out (Residential Only)) Relocate the meter from inside to outside per customer request	$260.00
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.	$260.00
Damage Meter Charge	$360.00

RIDER: H	BALANCING SERVICE RIDER

APPLICABILITY:

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

ENHANCED TITLE TRANSFER SERVICE:

In any Gas Transportation 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	$1.0474	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

BUDGET DEGREE DAYS

1. The purpose of this evidence is to provide the degree day forecasts for the Company's 2009[1] Test Year.

2. The 2009 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 3 weather zones within its franchise area using the Board approved 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 2009, the degree day forecasts are as follows:
    a. Central weather zone: 3,548 Environment Canada degree days; 3,514 Gas Supply degree days
    b. Eastern weather zone: 4,401 Environment Canada degree days; 4,363 Gas Supply degree days
    c. Niagara weather zone: 3,486 Environment Canada degree days; 3,435 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 2009. The model is estimated using data covering the period 1988 to 2007, 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 2009 is presented in Table 2 as well. The model is estimated over the period 1950 to 2007 a total of 58 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 1988 to 2007 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 1978 to 2007, a period of 30 years. Estimation results for the 20-Year Trend model are provided in Figure 3.

[2] The five-year weighted average for year *t* is calculated as $(5*DD_{t-2}+4*DD_{t-3}+3*DD_{t-4}+2*DD_{t-5}+DD_{t-6})/15$ while the five-year moving average at year *t* is computed as $(DD_{t-2}+DD_{t-3}+DD_{t-4}+DD_{t-5}+DD_{t-6})/5$ where DD is the actual degree day value.
[3] The 30 year moving average for year *t* is calculated as $(DD_{t-2}+DD_{t-3}+\ldots+DD_{t-30}+DD_{t-31})/30$ where DD is the actual degree day value.

Table 1
Environment Canada Degree Day Forecast – Central

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	Actual[1]	Trend	Fitted[2]
1988	4,076	1	4,063
1989	4,250	2	4,039
1990	3,631	3	4,014
1991	3,686	4	3,990
1992	4,112	5	3,965
1993	4,180	6	3,941
1994	4,115	7	3,916
1995	4,040	8	3,892
1996	4,177	9	3,867
1997	4,026	10	3,842
1998	3,220	11	3,818
1999	3,539	12	3,793
2000	3,826	13	3,769
2001	3,420	14	3,744
2002	3,630	15	3,720
2003	3,982	16	3,695
2004	3,798	17	3,671
2005	3,797	18	3,646
2006	3,378	19	3,622
2007	3,722	20	3,597
2009 Forecast		22	3,548

[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	4,727
1951	4,587	2	4,622	4,594	4,704
1952	4,404	3	4,647	4,661	4,729
1953	4,059	4	4,657	4,641	4,708
1954	4,707	5	4,572	4,556	4,691
1955	4,689	6	4,467	4,385	4,630
1956	4,799	7	4,516	4,465	4,652
1957	4,405	8	4,489	4,523	4,693
1958	4,736	9	4,531	4,626	4,732
1959	4,718	10	4,532	4,584	4,702
1960	4,451	11	4,667	4,652	4,681
1961	4,586	12	4,669	4,669	4,686
1962	4,826	13	4,622	4,596	4,659
1963	4,921	14	4,579	4,584	4,666
1964	4,569	15	4,663	4,667	4,674
1965	4,810	16	4,701	4,753	4,705
1966	4,683	17	4,671	4,709	4,687
1967	4,882	18	4,743	4,755	4,680
1968	4,780	19	4,762	4,735	4,656
1969	4,698	20	4,773	4,775	4,670
1970	4,899	21	4,745	4,778	4,679
1971	4,797	22	4,771	4,762	4,655
1972	5,014	23	4,788	4,805	4,669
1973	4,420	24	4,811	4,808	4,656
1974	4,725	25	4,838	4,876	4,681
1975	4,514	26	4,766	4,736	4,625
1976	5,008	27	4,771	4,723	4,611
1977	4,597	28	4,694	4,637	4,588
1978	4,939	29	4,736	4,741	4,628
1979	4,589	30	4,652	4,695	4,631
1980	4,920	31	4,756	4,790	4,639
1981	4,438	32	4,729	4,735	4,614
1982	4,647	33	4,810	4,798	4,613
1983	4,536	34	4,697	4,674	4,584
1984	4,535	35	4,707	4,658	4,566
1985	4,659	36	4,626	4,601	4,562
1986	4,501	37	4,615	4,570	4,544
1987	4,328	38	4,563	4,585	4,571
1988	4,640	39	4,576	4,564	4,549
1989	4,931	40	4,512	4,482	4,523
1990	4,250	41	4,532	4,524	4,535
1991	4,303	42	4,612	4,657	4,575
1992	4,861	43	4,530	4,537	4,535
1993	4,780	44	4,490	4,461	4,503
1994	4,730	45	4,597	4,585	4,526
1995	4,585	46	4,625	4,646	4,546
1996	4,603	47	4,585	4,681	4,579
1997	4,786	48	4,652	4,680	4,547
1998	3,828	49	4,712	4,664	4,508
1999	4,137	50	4,697	4,689	4,524
2000	4,543	51	4,506	4,399	4,430
2001	4,115	52	4,387	4,276	4,404
2002	4,381	53	4,379	4,328	4,434
2003	4,715	54	4,282	4,240	4,419
2004	4,637	55	4,201	4,273	4,468
2005	4,421	56	4,378	4,444	4,489
2006	4,037	57	4,478	4,531	4,494
2007	4,447	58	4,454	4,511	4,488
2009 Forecast		60	4,451	4,376	4,401

[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]
1978	4,020		3,643		
1979	3,799		3,642		
1980	3,932		3,649		
1981	3,729		3,664		
1982	3,724		3,678		
1983	3,642		3,682		
1984	3,716		3,691		
1985	3,651		3,697		
1986	3,603		3,707		
1987	3,441		3,712		
1988	3,693	1	3,705	3,688	3,697
1989	3,845	2	3,697	3,673	3,685
1990	3,307	3	3,705	3,658	3,682
1991	3,343	4	3,711	3,643	3,677
1992	3,759	5	3,697	3,627	3,662
1993	3,878	6	3,687	3,612	3,650
1994	3,780	7	3,692	3,597	3,644
1995	3,703	8	3,693	3,582	3,638
1996	3,786	9	3,701	3,566	3,634
1997	3,669	10	3,693	3,551	3,622
1998	2,980	11	3,704	3,536	3,620
1999	3,338	12	3,699	3,521	3,610
2000	3,596	13	3,670	3,505	3,588
2001	3,239	14	3,665	3,490	3,578
2002	3,415	15	3,659	3,475	3,567
2003	3,799	16	3,645	3,460	3,552
2004	3,632	17	3,631	3,444	3,538
2005	3,653	18	3,642	3,429	3,536
2006	3,163	19	3,639	3,414	3,526
2007	3,296	20	3,644	3,399	3,522
2009 Forecast		22	3,604	3,368	3,486

[1]Environment Canada heating degree day observations from St. Catherines Airport.
[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: 1988 2007 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	4,087.7780	124.30	32.89	0.00
TREND	-24.5341	10.38	-2.36	0.03

R-squared	0.24	F-statistic	5.59
Adjusted R-squared	0.19	F-prob	0.03

Figure 2
Energy Probe Forecasting Equation and Test Statistics - Eastern

Sample: 1950 2007 Included observations: 58

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	3,965.2320	1,246.81	3.18	0.00
ECEDD5WA	0.5863	0.74	0.79	0.43
ECEDD5MA	-0.4210	0.79	-0.53	0.60
TREND	-4.2578	2.11	-2.02	0.05

R-squared	0.12	F-statistic	2.40
Adjusted R-squared	0.07	F-prob	0.08

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

Sample: 1988 2007 Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	3,703.6420	116.49	31.79	0.00
TREND	-15.2502	9.72	-1.57	0.13

R-squared	0.12	F-statistic	2.46
Adjusted R-squared	0.07	F-prob	0.13

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 2009 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]**
1988	4,076	4,016	4,011
1989	4,250	4,190	4,175
1990	3,631	3,574	3,592
1991	3,686	3,649	3,644
1992	4,112	3,989	4,044
1993	4,180	4,040	4,109
1994	4,115	4,084	4,048
1995	4,040	3,991	3,977
1996	4,177	4,133	4,106
1997	4,026	3,966	3,964
1998	3,220	3,202	3,205
1999	3,539	3,497	3,506
2000	3,826	3,784	3,776
2001	3,420	3,400	3,394
2002	3,630	3,597	3,591
2003	3,982	3,949	3,922
2004	3,798	3,766	3,749
2005	3,797	3,750	3,748
2006	3,378	3,355	3,354
2007	3,722	3,659	3,678
2009 Forecast	3,548		3,514

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

Gas Supply degree days = 174.7552+0.9411(Environment Canada degree days)

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	4,381
1974	4,725	4,858	4,673
1975	4,514	4,229	4,471
1976	5,008	4,901	4,944
1977	4,597	4,604	4,550
1978	4,939	4,920	4,878
1979	4,589	4,550	4,542
1980	4,920	4,853	4,860
1981	4,438	4,361	4,399
1982	4,647	4,617	4,599
1983	4,536	4,515	4,492
1984	4,535	4,504	4,491
1985	4,659	4,648	4,610
1986	4,501	4,507	4,459
1987	4,328	4,268	4,293
1988	4,640	4,601	4,591
1989	4,931	4,883	4,870
1990	4,250	4,225	4,218
1991	4,303	4,270	4,269
1992	4,861	4,746	4,803
1993	4,780	4,715	4,726
1994	4,730	4,700	4,677
1995	4,585	4,530	4,539
1996	4,603	4,561	4,556
1997	4,786	4,711	4,731
1998	3,828	3,802	3,814
1999	4,137	4,112	4,110
2000	4,543	4,506	4,499
2001	4,115	4,071	4,089
2002	4,381	4,317	4,343
2003	4,715	4,663	4,663
2004	4,637	4,598	4,589
2005	4,421	4,397	4,381
2006	4,037	4,012	4,014
2007	4,447	4,411	4,407
2009 Forecast	4,401		4,363

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

Gas Supply degree days = 148.5190+0.9576(Environment Canada degree days)

Table 6
Determination of Gas Supply Equivalent Degree Days - Niagara

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	**Actual Environment Canada Degree Days**	**Actual Gas Supply Degree Days**	**Fitted Gas Supply Degree Days[1]**
1983	3,642	3,575	3,562
1984	3,716	3,739	3,623
1985	3,651	3,649	3,569
1986	3,603	3,384	3,530
1987	3,441	3,600	3,397
1988	3,693	3,611	3,604
1989	3,845	3,599	3,728
1990	3,307	3,511	3,288
1991	3,343	3,287	3,317
1992	3,759	3,636	3,658
1993	3,878	3,667	3,756
1994	3,780	3,616	3,675
1995	3,703	3,577	3,612
1996	3,786	3,808	3,680
1997	3,669	3,646	3,584
1998	2,980	2,931	3,019
1999	3,338	3,277	3,313
2000	3,596	3,553	3,524
2001	3,239	3,162	3,232
2002	3,415	3,304	3,376
2003	3,799	3,688	3,691
2004	3,632	3,485	3,554
2005	3,653	3,580	3,571
2006	3,163	3,079	3,169
2007	3,296	3,349	3,278
2009 Forecast	3,486		3,435

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

Gas Supply degree days = 575.7456+0.8201(Environment Canada degree days)

AVERAGE USE FORECASTING MODEL & ECONOMIC ASSUMPTIONS

1. The purpose of this evidence is to present the methodology used to forecast average use for Rate 1 revenue class 20 and Rate 6 revenue classes 12, 48 and 73[1] for the Company's 2009 Test Year. Rate 1 is the Company's residential rate class while Rate 6 is the Company's small apartment, commercial and industrial rate class.

2. The Company has continued to use econometric models to forecast average use for Rate 1 and Rate 6. The econometric methodology has been in place since 2001 and the forecasts produced and accepted in settlement proposals and Board decisions since. As shown in Tables 1 to 3, 5 and 8 below, the models exhibit a high R^2 and low Root Mean Squared Percentage Error ("RMSPE") indicating the regression model is an excellent predictor of average use. The forecasting methodology for the other revenue classes in Rate 1 and Rate 6 are very similar to the models presented in this exhibit.

3. In 2009[2] revenue class 20 is forecast to comprise 87% of Rate 1 volumes while revenue classes 12, 48 and 73 are forecast to collectively comprise 97% of Rate 6 volumes. Volumes for the remaining revenue classes in Rate 1 are forecast to comprise 13% of Rate 1 volumes while the remaining revenue classes in Rate 6 are forecast to comprise 3% of Rate 6 volumes.

[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.

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. Please refer to Exhibit C, Tab 2, Schedule 1 for a summary of the Company's gas volume budget.

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

Error Correction Model

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

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

8. The estimated models are used to generate a normalized forecast of average use. The main purpose of the normalized forecast is to compute average use such that the weather impact has been taken out. Using the estimated coefficients, weather

[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.

normalized average use data are obtained by replacing actual degree days in the model with budgeted degree days for 2009.

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 2007. Out-of-sample, or ex-ante, means that the model incorporates only a portion of the sample, in this case 1985 to 2005. Forecasts of average use are produced under both approaches and measured against actual average use from 2006 to 2007 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, on average, the model's forecast performance.

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

Col 1.	Col 2.	Col 3.
Forecast Error Method	Rate 1	Rate 6
In-Sample % Variance (2 Years)	0.86%	-0.19%
In-Sample RMSPE (2 Years)	0.90%	0.52%
Out-of-Sample % Variance (2 Years)	1.74%	-2.56%
Out-of-Sample RMSPE (2 Years)	1.75%	3.43%

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

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

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 an excellent predictor of general service average use.

TABLE 2

RATE 1 IN-SAMPLE FORECAST COMPARISON

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

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

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

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

TABLE 3
RATE 6 IN-SAMPLE FORECAST COMPARISON

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

[1]Board approved normalized average use from RP-2000-0040, RP-2001-0032 and RP-2002-0133, RP-2003-0203 200, EB-2005-0001 and EB-2006-0034 for 2001, 2002, 2003, 2005,2006 and 2007 respectively.

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

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

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

Breusch-Godfrey Serial Correlation LM Test[6]

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

Null Hypothesis: No serial correlation

Alternative Hypothesis: Serial correlation

ARCH Test

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

Null Hypothesis: No ARCH

Alternative Hypothesis: ARCH

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

Chow Forecast Test

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

Null Hypothesis: No structural change

Alternative Hypothesis: Structural change

Ramsey RESET Test

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

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

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

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

TABLE 4 - RATE 1 MODEL MNEMONICS

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

TABLE 5 - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Metro Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.54	7.01	0.00
LOG(CDD)	0.70	15.65	0.00
LOG(TIME)	-0.01	-1.15	0.26
LOG(REALCRCRPG)	-0.07	-2.37	0.03
LOG(MET20VINT)	0.40	2.56	0.02
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	221.72		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.07	0.95
DLOG(CDD)	0.74	25.12	0.00
DLOG(REALCRCRPG)	-0.03	-1.05	0.31
DLOG(MET20VINT)	0.70	1.68	0.11
ECM_MET20(-1)	-0.53	-2.09	0.05
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	190.75		0.00

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.23	1.81	0.09
LOG(CDD)	0.70	24.05	0.00
LOG(REALCRCRPG)	-0.11	-8.06	0.00
LOG(WES20VINT)	0.23	6.03	0.00
LOG(CENTEMP)	0.14	1.96	0.07
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	539.37		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.35	0.73
DLOG(CDD)	0.72	37.32	0.00
DLOG(REALCRCRPG)	-0.07	-3.87	0.00
DLOG(WES20VINT)	0.20	1.79	0.09
ECM_WES20(-1)	-0.77	-3.34	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	392.66		0.00

Central Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.12	0.15	0.88
LOG(CDD)	0.71	18.47	0.00
LOG(REALCRCRPG)	-0.09	-4.68	0.00
LOG(CEN20VINT)	0.33	9.33	0.00
LOG(CENTEMP)	0.27	3.35	0.00
R-squared	0.99		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	359.38		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.71	0.49
DLOG(CDD)	0.71	23.78	0.00
DLOG(REALCRCRPG)	-0.04	-1.42	0.17
DLOG(CEN20VINT)	0.31	2.36	0.03
ECM_CEN20(-1)	-1.21	-4.69	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	167.09		0.00

TABLE 5 CONTINUED - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Northern Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.48	0.62	0.54
LOG(CDD)	0.71	20.85	0.00
LOG(REALCRCRPG)	-0.11	-6.97	0.00
LOG(NOR20VINT)	0.27	8.88	0.00
LOG(CENTEMP)	0.24	2.83	0.01
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	574.92		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.41	0.68
DLOG(CDD)	0.71	28.64	0.00
DLOG(REALCRCRPG)	-0.09	-3.90	0.00
DLOG(NOR20VINT)	0.21	2.18	0.04
ECM_NOR20(-1)	-1.24	-5.17	0.00
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	226.47		0.00

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.55	4.50	0.00
LOG(EDD)	0.78	18.64	0.00
LOG(TIME)	-0.01	-1.20	0.24
LOG(REALERCRPG)	-0.08	-3.71	0.00
LOG(ERC20VINT)	0.19	5.17	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	362.29		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.96	0.01
DLOG(EDD)	0.78	24.49	0.00
DLOG(REALERCRPG)	-0.05	-1.81	0.09
ECM_ERC20(-1)	-1.12	-4.00	0.00
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	219.23		0.00

Niagara Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.30	5.68	0.00
LOG(NDD)	0.71	14.03	0.00
LOG(TIME)	-0.04	-2.78	0.01
LOG(REALNRCRPG)	-0.13	-3.72	0.00
LOG(NRC20VINT)	0.32	1.77	0.09
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	211.19		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-3.05	0.01
DLOG(NDD)	0.71	22.21	0.00
DLOG(REALNRCRPG)	-0.06	-2.19	0.04
ECM_NRC20(-1)	-0.63	-2.89	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	188.51		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	0.02	0.01	0.23	0.18	1.07	0.80
	P Value	0.88	0.93	0.63	0.67	0.30	0.37
ARCH Test	Test Statistic	0.40	0.05	0.97	0.78	0.44	0.97
	P Value	0.53	0.83	0.32	0.38	0.51	0.32
Chow Forecast Test: Forecast from 2006 to 2007	Test Statistic	2.48	0.37	0.83	0.50	1.42	0.27
	P Value	0.12	0.70	0.45	0.62	0.27	0.77
Ramsey RESET Test	Test Statistic	0.87	0.54	0.04	0.13	0.00	0.44
	P Value	0.36	0.47	0.84	0.73	0.97	0.51

TABLE 7 - RATE 6 MODEL MNEMONICS

Mnemonic	Definition
C	Constant Term
LOG(X)	Logarithm of Variable X
DLOG(X)	$LOG(X_t) - LOG(X_{t-1})$, First Difference of Logarithm of Variable X
CDD, EDD, NDD	Balance Point Heating Degree Days for Central, Eastern and Niagara Weather Zones
CENTEMP	Central Weather Zone Employment
EASTEMP	Eastern Weather Zone Employment
NIAGEMP	Niagara Weather Zone Employment
REALCRCCPG	Real Commercial Gas Price for the Central Weather Zone
REALERCCPG	Real Commercial Gas Price for the Eastern Weather Zone
REALNRCCPG	Real Natural Gas Price for the Niagara Weather Zone
ONTGDP	Ontario Real Gross Domestic Product
MANUFACTURING	Ontario Manufacturing Industry Real Domestic Product
CRCCOMVAC	GTA Commercial Vacancy Rate
CRCINDVAC	GTA Industrial Vacancy Rate
TIME	Time Trend
DUMPRE1991	Dummy Variable for Structural Break Prior to 1991
DUMCRC12	Dummy Variable for Migration Impact
DUMCRC73	Dummy Variable for Migration Impact
DUMNRC73	Dummy Variable for Migration Impact
DUMXXXX	Dummy Variable for Year XXXX
AR(1)	First-order autoregressive process term
ECM_Region	Error Correction Term for Each Region

TABLE 8 - RATE 6 REVENUE CLASS 12 REGRESSION EQUATIONS

Central Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	3.24	5.86	0.00
LOG(CDD)	0.64	23.59	0.00
LOG(TIME)	-0.03	-5.92	0.00
LOG(CENTEMP)	0.40	7.35	0.00
LOG(REALCRCCPG)	-0.05	-3.27	0.01
DUM2005	-0.04	-3.60	0.00
DUM2006	0.06	5.24	0.00
DUMCRC12	0.22	20.49	0.00
AR(1)	-0.28	-1.14	0.27
R-squared	0.99		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	149.852		0.00

Eastern Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	6.64	12.79	0.00
LOG(EDD)	0.53	8.27	0.00
LOG(TIME)	-0.02	-4.45	0.00
LOG(REALERCCPG)	-0.03	-1.81	0.09
R-squared	0.88		
Adjusted R-squared	0.86		
S.E. of regression	0.02		
F-statistic	45.59		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.63	0.53
DLOG(EDD)	0.56	11.56	0.00
DLOG(REALERCCPG)	-0.05	-1.47	0.16
ECM_ERC12(-1)	-0.95	-3.40	0.00
R-squared	0.92		
Adjusted R-squared	0.90		
S.E. of regression	0.02		
F-statistic	66.60		0.00

Niagara Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	4.90	5.57	0.00
LOG(NDD)	0.56	10.16	0.00
LOG(TIME)	-0.02	-3.17	0.01
LOG(REALNRCCPG)	-0.03	-1.42	0.17
LOG(NIAGEMP)	0.25	2.15	0.05
R-squared	0.88		
Adjusted R-squared	0.85		
S.E. of regression	0.02		
F-statistic	33.26		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.53	0.60
DLOG(NDD)	0.49	15.76	0.00
DLOG(NIAGEMP)	0.20	2.41	0.03
ECM_NRC12(-1)	-1.06	-3.13	0.01
AR(1)	0.33	0.89	0.39
R-squared	0.93		
Adjusted R-squared	0.92		
S.E. of regression	0.02		
F-statistic	55.01		0.00

TABLE 8 CONTINUED - RATE 6 REVENUE CLASS 48 REGRESSION EQUATIONS

Central Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.03	-0.03	0.97
LOG(CDD)	0.87	14.95	0.00
LOG(TIME)	-0.12	-9.03	0.00
LOG(CRCCOMVAC)	-0.07	-4.47	0.00
LOG(ONTGDP)	0.26	4.25	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	181.83		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-1.39	0.18
DLOG(CDD)	0.85	30.69	0.00
DLOG(TIME)	-0.07	-4.14	0.00
DLOG(CRCCOMVAC)	-0.04	-3.10	0.01
DLOG(ONTGDP)	0.30	2.20	0.04
ECM_CRC48(-1)	-0.85	-5.49	0.00
R-squared	0.99		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	210.73		0.00

Eastern Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.45	1.67	0.11
LOG(EDD)	0.73	11.57	0.00
LOG(TIME)	-0.16	-15.75	0.00
LOG(ONTGDP)	0.22	4.73	0.00
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.02		
F-statistic	298.92		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-1.75	0.10
DLOG(EDD)	0.81	21.68	0.00
DLOG(TIME)	-0.09	-2.11	0.05
DLOG(ONTGDP)	0.25	2.43	0.03
ECM_ERC48(-1)	-1.21	-2.71	0.02
AR(1)	-0.37	-0.82	0.43
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	127.35		0.00

Niagara Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.91	-0.50	0.62
LOG(NDD)	0.68	10.80	0.00
LOG(TIME)	-0.09	-4.03	0.00
LOG(REALNRCCPG)	-0.17	-3.79	0.00
LOG(ONTGDP)	0.41	3.10	0.01
R-squared	0.92		
Adjusted R-squared	0.90		
S.E. of regression	0.02		
F-statistic	49.50		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-1.12	0.28
DLOG(NDD)	0.68	21.29	0.00
DLOG(REALNRCCPG)	-0.11	-3.91	0.00
DLOG(ONTGDP)	0.42	2.01	0.06
ECM_NRC48(-1)	-1.23	-4.95	0.00
AR(1)	0.57	2.26	0.04
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	87.99		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	5.81	3.89	0.00
LOG(CDD)	0.47	6.34	0.00
LOG(TIME)	-0.06	-2.32	0.03
LOG(CRCINDVAC)	-0.05	-2.24	0.04
LOG(ONTGDP)	0.13	1.20	0.25
DUMPRE1991	-0.07	-2.82	0.01
DUM2000	0.06	2.34	0.03
DUMCRC73	0.09	3.40	0.00
R-squared	0.94		
Adjusted R-squared	0.91		
S.E. of regression	0.02		
F-statistic	33.311		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.02	-2.22	0.04
DLOG(CDD)	0.53	12.27	0.00
DLOG(TIME)	-0.06	-2.11	0.05
DLOG(ONTGDP)	0.50	2.62	0.02
DUM2000	0.06	2.94	0.01
DUMCRC73	0.09	4.78	0.00
ECM_CRC73(-1)	-1.18	-5.83	0.00
R-squared	0.95		
Adjusted R-squared	0.93		
S.E. of regression	0.02		
F-statistic	46.21		0.00

Eastern Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-219,461.60	-3.67	0.00
EDD	13.83	1.47	0.16
TIME	-6,163.62	-9.07	0.00
EASTEMP	631.43	6.99	0.00
DUM2003	72,280.83	6.89	0.00
DUM2004	-94,026.74	-9.60	0.00
R-squared	0.94		
Adjusted R-squared	0.93		
S.E. of regression	9,019.76		
F-statistic	58.38		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-6,792.30	-2.58	0.02
D(EDD)	13.50	1.80	0.09
D(EASTEMP)	761.76	3.38	0.00
DUM2003	69,157.17	5.87	0.00
DUM2004	-165,191.10	-16.23	0.00
DUM2005	89,032.88	9.16	0.00
ECM_ERC73(-1)	-1.08	-3.46	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	9,422.17		
F-statistic	96.11		0.00

Niagara Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-6.41	-1.68	0.11
LOG(NDD)	0.47	1.80	0.09
LOG(TIME)	-0.18	-3.92	0.00
LOG(REALNRCCPG)	-0.22	-2.08	0.05
LOG(MANUFACTURING)	1.25	4.84	0.00
DUM2002	-0.38	-3.99	0.00
DUMNRC73	0.36	3.64	0.00
R-squared	0.76		
Adjusted R-squared	0.67		
S.E. of regression	0.09		
F-statistic	8.37		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.02	-0.81	0.43
DLOG(NDD)	0.48	2.49	0.02
DLOG(MANUFACTURING)	0.55	1.47	0.16
DUM2002	-0.31	-3.38	0.00
DUM2003	0.33	3.85	0.00
DUMNRC73	0.40	4.82	0.00
ECM_NRC73(-1)	-0.91	-3.50	0.00
R-squared	0.89		
Adjusted R-squared	0.84		
S.E. of regression	0.08		
F-statistic	19.40		0.000

TABLE 9-RATE 6
Model Diagnostic Tests

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.	Col 9.	Col 10.	Col 11.
		Revenue Class 12 (Apartment) Model Diagnostic Tests			**Revenue Class 48 (Commercial) Model Diagnostic Tests**			**Revenue Class 73 (Industrial) Model Diagnostic Tests**		
Test		Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone
Breusch-Godfrey Serial Correlation LM Test	Test Statistic	0.02	0.03	2.49	2.80	0.10	0.15	0.82	1.13	2.89
	P Value	0.90	0.87	0.11	0.09	0.75	0.69	0.37	0.29	0.09
ARCH Test	Test Statistic	0.79	0.08	0.23	2.27	0.83	0.77	1.45	4.63	0.52
	P Value	0.38	0.78	0.63	0.13	0.36	0.38	0.23	0.03	0.47
Chow Forecast Test: Forecast from 2006 to 2007	Test Statistic	144.41*	2.40	0.14	0.55	1.58	1.16	10.74**	0.58	12.46***
	P Value	0.00	0.12	0.87	0.59	0.24	0.34	0.00	0.57	0.00
Ramsey RESET Test	Test Statistic	0.06	2.51	2.73	0.33	2.39	0.68	0.46	1.97	2.45
	P Value	0.82	0.13	0.12	0.58	0.14	0.42	0.51	0.18	0.14

* without dumcrc12
** without dumcrc73
*** without dumnrc73

14. Driver variable assumptions are presented in Table 10 in year over year growth rates. Major driver variables in the model include balance point heating degree days adjusted for billing cycles, vintage, time trend, real energy prices and economic variables. Driver variable assumptions are based on economic assumptions from the Economic Outlook, Spring 2008.

15. Higher natural gas prices have a negative impact on average use. Sharp increases will have two effects. First, it will cause customers to change their fuel use habits, for example, by lowering thermostat settings. Second, price increases will likely cause customers to purchase more efficient furnaces and other appliances. In addition, homeowners could retrofit older residences in order to reduce their energy consumption. Real energy prices are used in the model. The Consumer Price Index ("CPI") is used to convert nominal gas prices to real gas prices. Nominal energy price forecasts are based on the Fekete's price forecast produced in April 2008.

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

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

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

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

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

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

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

[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.

customers are added to the revenue class the declining ratio leads to lower average use over time. Thus the sign of this variable's coefficient is positive.

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

TABLE-10
Economic Outlook

CANADA & U.S.

CALENDAR YEAR	2003	2004	2005	2006	2007	2008F	2009F
REAL GDP (% CHANGE)							
CANADA	1.9	3.1	3.1	2.8	2.7	1.8	2.0
U.S.	2.5	3.6	3.1	2.9	2.3	1.6	2.1
REAL EXPORTS (% CHANGE)	-2.3	4.8	2.2	0.7	0.9	-1.2	1.9
REAL IMPORTS (% CHANGE)	4.1	8.3	7.5	5.0	5.7	6.0	4.2
HOUSING STARTS (000's)	218	233	225	227	228	209	192
UNEMPLOYMENT RATE (%)	7.6	7.2	6.8	6.3	6.0	6.0	6.1
EMPLOYMENT GROWTH (% CHANGE)	2.4	1.8	1.4	1.9	2.3	1.4	1.0
CONSUMER PRICES (% CHANGE)							
CANADA	2.8	1.9	2.2	2.0	2.1	1.8	1.8
U.S.	2.3	2.7	3.4	3.2	2.9	3.1	2.4

Witness: J. Denomy

TABLE-10 CONTINUED
Economic Outlook

ONTARIO

CALENDAR YEAR	2003	2004	2005	2006	2007	2008F	2009F
REAL GDP (% CHANGE)	1.6	2.9	2.6	2.3	2.0	1.4	2.1
REAL MANUFACTURING OUTPUT (% CHANGE)	-0.1	1.1	-0.4	-3.9	0.5	0.7	0.6
HOUSING STARTS (000's)	85.2	85.1	78.8	73.4	68.1	64.6	62.3
UNEMPLOYMENT RATE (%)	6.9	6.8	6.6	6.3	6.4	6.5	6.6
EMPLOYMENT GROWTH (% CHANGE)	3.0	1.7	1.3	1.5	1.5	1.0	0.9
CONSUMER PRICES (% CHANGE)	2.7	1.9	2.2	1.8	1.8	1.6	1.7
RETAIL SALES (% CHANGE)	3.4	3.2	4.8	4.1	3.8	2.1	2.3
WAGE RATE (% CHANGE)	10.0	0.8	6.0	5.1	3.6	3.5	3.9
REAL RESIDENTIAL NATURAL GAS PRICE (% CHANGE)	19.6	1.9	8.8	8.9	-11.4	5.3	5.2
REAL COMMERCIAL NATURAL GAS PRICE (% CHANGE)	22.1	2.3	10.1	10.0	-12.7	5.8	4.5

TABLE-10 CONTINUED
Economic Outlook

REGIONS

CALENDAR YEAR	2003	2004	2005	2006	2007	2008F	2009F
GTA							
HOUSING STARTS (000's)	48.1	44.7	43.0	38.8	35.7	40.3	36.2
SINGLES	22.3	21.5	17.7	15.9	16.1	14.3	13.4
MULTIPLES	25.8	23.2	25.4	22.9	19.7	26.0	22.8
CONSUMER PRICES (% CHANGE)	3.0	1.7	1.8	1.6	1.9	1.3	1.9
UNEMPLOYMENT RATE (%)	7.1	6.8	6.8	6.3	6.5	6.4	6.2
EMPLOYMENT GROWTH (% CHANGE)	3.4	2.3	1.8	1.8	2.0	2.1	2.6
COMMERCIAL VACANCY RATE (%)	11.4	10.6	9.3	7.3	6.3	5.6	5.6
INDUSTRIAL VACANCY RATE (%)	5.1	5.0	4.9	5.1	5.4	5.5	5.5
VINTAGE METRO REGION CENTRAL WEATHER ZONE (% CHANGE)	-1.4	-0.9	-1.1	-1.1	-1.8	-1.6	-1.5
VINTAGE WESTERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-4.4	-3.8	-3.3	-2.5	-2.7	-2.5	-2.4
VINTAGE CENTRAL REGION CENTRAL WEATHER ZONE (% CHANGE)	-4.0	-4.0	-3.6	-3.8	-3.1	-2.8	-2.7
VINTAGE NORTHERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-5.0	-4.2	-3.7	-3.8	-3.6	-3.3	-3.2
EASTERN							
HOUSING STARTS (000's)	6.5	7.5	5.2	6.1	6.8	6.6	6.3
SINGLES	3.2	3.5	2.5	2.7	3.1	2.8	2.5
MULTIPLES	3.4	4.0	2.6	3.4	3.6	3.7	3.9
CONSUMER PRICES (% CHANGE)	2.5	1.9	2.3	1.7	1.9	1.0	2.0
UNEMPLOYMENT RATE (%)	6.9	6.6	6.7	5.4	5.7	5.4	6.2
EMPLOYMENT GROWTH (% CHANGE)	3.9	-0.7	1.7	3.2	1.2	2.8	0.7
VINTAGE EASTERN WEATHER ZONE (% CHANGE)	-3.5	-3.4	-3.0	-2.7	-2.8	-2.4	-2.2
NIAGARA							
HOUSING STARTS (000's)	1.8	2.0	1.5	1.4	1.3	1.3	1.2
SINGLES	1.3	1.5	1.1	0.9	0.9	0.9	0.9
MULTIPLES	0.5	0.6	0.4	0.4	0.4	0.5	0.3
UNEMPLOYMENT RATE (%)	7.0	7.3	7.0	6.4	6.8	6.3	6.6
EMPLOYMENT GROWTH (% CHANGE)	1.8	-2.5	3.1	-1.2	1.4	3.2	-0.4
VINTAGE NIAGARA WEATHER ZONE (% CHANGE)	-1.4	-1.4	-1.4	-1.2	-1.1	-1.0	-0.9

TABLE-10 CONTINUED
Economic Outlook

INTEREST RATE & EXCHANGE RATE FORECAST

CALENDAR YEAR		2003	2004	2005	2006	2007	2008F	2009F
Canada								
Interest Rates	**Overnight Rate**	2.94	2.25	2.67	4.06	4.35	3.04	2.96
	Bank Rate	3.19	2.50	2.92	4.31	4.60	3.29	3.21
	Prime Rate	4.69	4.00	4.42	5.81	6.10	4.79	4.71
	1 Year Mortgage Rate	4.84	4.59	5.06	6.28	6.90	6.15	5.66
	3 Year Mortgage Rate	5.82	5.65	5.59	6.45	7.09	6.65	6.33
	5 Year Mortgage Rate	6.39	6.23	5.99	6.66	7.07	6.88	6.68
Money Markets	**1 Month T-Bills**	2.81	2.12	2.56	3.93	4.05	2.70	2.72
	3 Month T-Bills	2.85	2.22	2.73	4.04	4.12	2.83	2.84
	6 Month T-Bills	2.90	2.32	2.87	4.12	4.26	3.06	2.96
	1 Year T-Bills	3.01	2.55	3.09	4.19	4.32	3.21	3.20
	1 Month Bankers Acceptance	2.94	2.27	2.74	4.13	4.51	3.71	3.22
	3 Month Bankers Acceptance	2.95	2.31	2.84	4.19	4.57	3.92	3.56
	1 Month Commercial Paper	2.94	2.28	2.75	4.15	4.57	3.72	3.23
	3 Month Commercial Paper	2.94	2.31	2.84	4.21	4.63	3.93	3.57
Benchmark Government Bond Yields	**2 Year**	3.25	2.97	3.21	4.05	4.19	3.31	3.46
	3 Year	3.48	3.36	3.35	4.08	4.21	3.49	3.68
	5Year	4.00	3.82	3.59	4.12	4.22	3.71	3.92
	7 Year	4.39	4.22	3.81	4.16	4.24	3.82	4.06
	10Year	4.79	4.59	4.05	4.22	4.28	3.96	4.22
	30 Year	5.34	5.14	4.40	4.28	4.32	4.12	4.35
United States								
Interest Rates	**Federal Funds Rate**	1.10	1.40	3.25	5.02	5.00	1.77	1.60
	Prime Rate	4.12	4.34	6.19	7.96	8.05	5.20	4.58
	30 Year Mortgage Rate	5.82	5.84	5.87	6.41	6.34	5.77	5.79
Money Markets	**1 Month T-Bills**	1.02	1.27	3.00	4.75	4.40	1.55	1.44
	3 Month T-Bills	1.03	1.40	3.21	4.85	4.47	1.61	1.49
	6 Month T-Bills	1.08	1.61	3.50	4.99	4.61	1.82	1.61
	1 Month Non-Financial Commercial Paper	1.11	1.38	3.24	4.97	5.02	2.13	1.51
	3 Month Non-Financial Commercial Paper	1.11	1.49	3.40	5.03	4.99	2.15	1.55
	1 Month Financial Commercial Paper	1.13	1.40	3.27	5.00	5.07	2.20	1.53
	3 Month Financial Commercial Paper	1.13	1.52	3.44	5.06	5.13	2.38	1.63
Treasury Bond Yields	**1 Year**	1.24	1.89	3.62	4.93	4.52	1.90	1.82
	2 Year	1.65	2.38	3.85	4.82	4.36	2.02	2.23
	3 Year	2.11	2.78	3.93	4.77	4.34	2.18	2.57
	5 Year	2.97	3.43	4.05	4.75	4.43	2.66	3.13
	7 Year	3.52	3.87	4.15	4.76	4.50	2.98	3.47
	10 Year	4.02	4.27	4.29	4.79	4.63	3.37	3.84
	20 Year	4.96	5.05	4.65	4.99	4.91	3.97	4.39
	30 Year	4.91	5.00	4.60	4.87	4.83	3.93	4.34
Exchange Rate	**$CDN/$US**	1.40	1.30	1.21	1.13	1.07	1.02	1.02
	$US/$CDN	0.72	0.77	0.83	0.88	0.94	0.98	0.98

Risks to the Forecast

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

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

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

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

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

Conclusion

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

2009 PROPOSED RATES

1. This evidence outlines the Company's proposal with respect to 2009 rates within its Revenue Cap per Customer Incentive Regulation Model approved in EB-2007-0615. The evidence lays out the development of the proposed 2009 rates including the proposed recovery of the 2009 revenue requirement. The Company also filed evidence under Exhibit C, Tab 1, Schedule 4 that addresses proposed changes to the Rate Handbook.

2. The Company is seeking Ontario Energy Board ("Board") approval, by December 15, 2008, of each of the following:
    a. recovery of the 2009 revenue requirement from all elements of the Company's rates;
    b. the proposed rates for each customer class; and
    c. the proposed changes to the Rate Handbook.

3. In order to implement the 2009 proposed rates by January 1, 2009, the Company is seeking approval of Phase I rate related changes, by means of a Rate Order, by December 15, 2008.

4. The Rate Handbook filed under Exhibit B, Tab 1, Schedule 9 reflects the proposed changes to the rates only. Except for the proposed rate changes, all other components of the Rate Handbook filed under this exhibit remain as approved in EB-2008-0263 (October 1, 2008 QRAM). As per the Company's application filed at Exhibit A, Tab 2, Schedule 1, page 3, this Rate Handbook will be reviewed in Phase I of the proceeding.

Witnesses: J. Collier
A. Kacicnik

5. The Phase II changes the Company is proposing to the Rate Handbook, be it to the terms and conditions or housekeeping changes, do not have an impact on the development of rates. Therefore, they can be approved and implemented in a subsequent rate order.

6. The Rate Handbook incorporating both the proposed 2009 rates as well as the proposed changes to the Rate Handbook can be found at Exhibit B, Tab 3, Schedule 2. This version of the Rate Handbook will be reviewed in Phase II of the proceeding.

Components of the 2009 Revenues

7. The derivation of the Company's 2009 revenues reflecting the Revenue Cap per Customer incentive regulation model is presented at Exhibit B, Tab 1, Schedule 2, page 1. Row 26 of the same exhibit represents total proposed revenues for 2009 in the amount of $3,363.84 million.

8. As shown at rows 24, 25, and 26, the 2009 proposed revenues consist of:

2009 Distribution Revenues	$ 974.14
2009 Gas Cost to Operations	$2,389.70
2009 Total Revenues	$3,363.84

9. The 2009 distribution revenues are comprised of: a) 2009 base distribution revenue in the amount of $802.14 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 $172.0 million (Row 23).

10. The 2009 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 5, Schedule 1.

2009 Rate Impacts

11. The Company has designed rates to recover the proposed 2009 revenues of $3,363.8 million. Table 1 below provides a summary of the resulting rate impacts. 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.

12. These rate impacts are relative to the existing October 1, 2008 QRAM Board approved rates filed under EB-2008-0263 and reflect the recovery of the proposed 2009 revenue requirement, the proposed 2009 volumetric forecast, and the proposed 2009 Gas Cost to Operations budget.

Table 1: 2009 Proposed Average Rate Impacts

Rate Class	T-Service Rate Impact
1	0.5%
6	0.4%
9	0%
100	-0.3%
110	-0.3%
115	-0.4%
135	-0.1%
145	0%
170	-0.4%
200	0%
	Delivery Rate Impact
125	0.1%
300	0.1%

13. The 2009 rate impacts are lower for all rate classes than the threshold levels requiring additional variance explanation for 2009 as outlined in the

EB-2007-0615 Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, Appendix F, page 60. 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

14. Rate design exhibits are filed at Exhibit B, Tab 3, Schedules 3 to 9. The exhibits present the proposed recovery of the 2009 revenues. The schedules are organized in the following manner:

a) Schedule 3 of Exhibit B, Tab 3 summarizes, by rate class, and rate component, the revenues at proposed rates which are forecast to be recovered in 2009. 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-2008-0263 (October 1, 2008 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-2008-0263 (October 1, 2008 QRAM) rates are shown at Schedule 9.

15. The following paragraphs outline the process the Company used to design its commodity, transportation, load balancing, and distribution rates.

Rate Design Exhibits

16. The gas supply revenues reflect the 2009 forecast of Gas Costs to Operations in the amount of $2,389.7 million including changes to the Company's 2009 gas supply portfolio relative to the 2008 gas supply portfolio as well as storage and storage associated transportation costs. These elements are not captured through the Company's QRAM. The Company's QRAM methodology adjusts rates in each quarter of a fiscal year to reflect changes in commodity and upstream transportation costs.

17. The Company's existing October 1, 2008 QRAM rates have a Purchased Gas Variance Account ("PGVA") reference price of $387.103 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 2009 yields a PGVA reference price of $384.768 10^3m^3, which is a decrease from the October 2008 QRAM level.

18. 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) are recovered through the Company's delivery charges.

19. 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

20. The distribution revenues include a base 2009 distribution revenue requirement of $802.14 million, which is derived using the proposed Revenue Cap per Customer incentive regulation escalation formula, and distribution revenue requirement of $172 million associated with the Y-factors.

21. 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.

22. The Company used allocators reflecting 2009 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 revenue requirements were assigned to the customer classes based on specific drivers for that type of expenditure such as peak demand or customer numbers.

Rate Design: 2009 Proposed Rates

23. In the rate design process, consistent with the approach to design of rates in a cost of service environment, the Company used the assignment of the 2009 revenue requirement (Exhibit B, Tab 3, Schedule 10, pp. 1 - 9) as a guide to establish that the proposed rates are reasonable.

24. The Company has designed the proposed 2009 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.

25. The Company also validated that there is an appropriate assignment of revenue responsibility among rate classes and that rates remain related to revenue requirement by measuring the proposed revenues to be recovered from each rate class relative to the assignment of the test year revenue requirement. This validation is provided at Exhibit B, Tab 3, Schedule 10, pages 1 and 2.

Other

26. As outlined at Exhibit B, Tab 1, Schedule 5: Gas Volume Budget, the Company is not forecasting any customers/volumes under Rate 100 in 2009. This reflects customer migration from Rate 100 to Rate 6 that the Company has recently experienced.

27. Since 2004 the bill difference between contract rates, particularly Rate 100 and Rate 6, has steadily decreased mainly as a result of:

i. the redesign of Rate 6 (2004); and
ii. the four (4) year phase-in of upstream transportation cost allocation changes (October 1, 2004 to October 1, 2007).

29. The completion of the four year phase-in on October 1, 2007 resulted in a high number of customers in Rate 100 having lower annual bills on Rate 6 as compared to Rate 100. Having said that, Rate 100 has no load factor requirement and its customers load profile is that of a customer with a heat sensitive load (i.e., winter volumes are much higher than summer volumes), which is the load profile characteristic of the Rate 6 class also. The Company anticipated this migration into account in its 2008 forecast.

30. In 2008 and for 2009, the Company increased the Rate 6 monthly customer charge as per the EB-2007-0615 Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, Issue 12.3.1. With the introduction of higher monthly customer charges on Rate 6, and a corresponding decrease in Rate 6 delivery charges, all Rate 100 customers are forecast to pay a lower bill on Rate 6 as compared to Rate 100. As a result, the Company reflected this incremental migration in its 2009 forecast.

31. Although the Company has forecast that all previous Rate 100 customers will take service under Rate 6, existing or new customers may elect to take service under Rate 100. The Company does not plan to discontinue Rate 100 service.

RATE HANDBOOK

Filed: 2008-09-26
EB-2008-0219
Exhibit B
Tab 3
Schedule 2

Deleted: 4
Deleted: 02
Deleted: Final Rate Order
Deleted: 7
Deleted: 0615
Deleted: C
Deleted: 6
Deleted: 1

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

INDEX

PART I:	GLOSSARY OF TERMS	Page 1
PART II:	RATES AND SERVICES AVAILABLE	Page 4
PART III:	TERMS AND CONDITIONS - APPLICABLE TO ALL SERVICES	Page 5
PART IV:	TERMS AND CONDITIONS - DIRECT PURCHASE ARRANGEMENTS	Page 7
PART V:	RATE SCHEDULES	Page 10

Deleted: 3
Deleted: 9

Deleted: 8
Deleted: 7
Deleted: 01

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 ("m³"): 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.

Deleted: 8
Deleted: 07
Deleted: 8
Deleted: 01

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.

Deleted: A contract clause intended to excuse one or more ¶ parties from their obligations under a contract, in situations where performance is frustrated by unusual or severe circumstances beyond their control such as flood, fire, war, or prolonged labour strike.

Deleted: 8

Deleted: 07

Deleted: 8

Deleted: 01

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.

Deleted: 8

Deleted: 07

Deleted: 8

Deleted: 01

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

Deleted: 8
Deleted: 07
Deleted: 8
Deleted: 01

Applicant may be able to reduce the costs otherwise payable under Bundled T-Service.

D. Western Delivery T-Service Arrangement

In a Western Delivery T-Service Arrangement the Applicant contracts to deliver each day to a point on the TransCanada PipeLines Ltd. transmission system in Western Canada a Mean Daily Volume of gas plus fuel gas. Delivery from that point to the Terminal Location is carried out by the Company using its contracted capacity on the TransCanada PipeLines Limited. system and its gas distribution network. Unbundled T-Service in Ontario is not available with the Western Delivery Option.

An Applicant desiring to receive Transportation Service or to establish a Buy/Sell Agreement must first enter into the applicable written agreements with the Company.

PART III

TERMS AND CONDITIONS APPLICABLE TO ALL SERVICES

The provisions of this PART III are applicable to, and only to, Sales Service and Transportation Service.

SECTION A - AVAILABILITY

Unless otherwise stated in a Rate Schedule, the Company's rates and services are available throughout the entire franchised area serviced by the Company. Transportation service and/or sales service will be provided subject to the Company having the capacity in its gas distribution network to provide the service requested. When the Company is requested to supply the natural gas to be delivered, service shall be available subject to the Company having available to it a supply of gas adequate to meet the requirement without jeopardizing the supply to its existing customers.

Service shall be made available after acceptance by the Company of an application for service to a Terminal Location at which the natural gas will be used.

SECTION B - ENERGY CONTENT

The price of natural gas sold at a Terminal Location is based on the assumption that each cubic metre of such natural gas contains a certain number of megajoules of energy which number is specified in the Rate Schedules. Variations in cost resulting from the energy content of the gas actually delivered to the Company by its supplier(s) differing from the assumed energy content will be recorded and used to adjust future bills. Such adjustments shall be made in accordance with practices approved from time to time by the Ontario Energy Board.

SECTION C - SUBSTITUTION PROVISION

The Company may deliver gas from any standby equipment provided that the gas so delivered shall be reasonably equivalent to the natural gas normally delivered.

SECTION D - BILLS

Bills will be mailed or delivered monthly or at such other time period as set out in the Service Contract. Gas consumption to which the Company's rates apply will be determined by the Company either by meter reading or by the Company's estimate of consumption where meter reading has not occurred. The rates and charges applicable to a billing month shall be those applicable to the calendar month which includes the last day of the billing month.

SECTION E - MINIMUM BILLS

The minimum bill per month applicable to service under any particular Rate Schedule shall be the Customer Charge plus any applicable Contract Demand Charges for Delivery, Gas Supply Load Balancing, and Gas Supply and any applicable Direct Purchase Administration Charge, all as provided for in the applicable Rate Schedule.

In addition, for service under each of the Large Volume Distribution Contact Rates, if in a contract year a volume of gas equal to or greater than the product of the Contract Demand multiplied by a contractually specified multiple of the Contract Demand ("Minimum Annual Volume") is not taken at the Terminal Location the Applicant shall pay, in addition to the minimum monthly bills, the amount obtained when the difference between the Minimum Annual Volume and the volume taken in the contract year (such difference being the Annual Volume Deficiency) is multiplied by the applicable Minimum Bill Charge(s) as provided for in the applicable Rate Schedule. Notwithstanding the foregoing, the Minimum Annual Volume shall be the greater of the Minimum Annual Volume as determined above and 340,000 m^3.

If gas deliveries to the Terminal Location have been ordered to be curtailed or discontinued in a contract year at the request of the Company and have been curtailed or discontinued as ordered, the Minimum Annual Volume shall be reduced for each day of curtailment or discontinuance by the excess of the Contract Demand over the volume delivered to the Terminal Location on such day.

SECTION F - PAYMENT CONDITIONS

Enbridge Gas Distribution charges are due when the bill is received, which is considered to be three days after the date the bill is rendered, or within such other time period as set out in the Service Contract. A late payment charge of 1.5% per month (19.56% effectively per annum) of all of the unpaid Enbridge Gas Distribution charges, including all applicable federal and provincial taxes, is applied to the account on the seventeenth (17th) day following the

Deleted: ¶

Deleted: ¶

Deleted: ¶

Deleted: 8

Deleted: 07

Deleted: 8

Deleted: 01

date the bill is due or within such other time period as set out in the Service Contract.

SECTION G - TERM OF ARRANGEMENT

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

SECTION H - RESALE PROHIBITION

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

SECTION I - MEASUREMENT

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

SECTION J - RATES IN CONTRACTS

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

SECTION K - ADVICE RE: CURTAILMENT

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

SECTION L - DAILY DELIVERED VOLUMES

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

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

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

SECTION M - AUTHORIZED OVERRUN GAS

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

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

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

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

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

plus

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

Deleted:

Deleted: ¶

Deleted: 8

Deleted: 07

Deleted: 8

Deleted: 01

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

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

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

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

SECTION O – COMPANY RESPONSIBILTY AND LIABILITY

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;

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

(b) for any reason related to dangerous or hazardous circumstances, including emergencies or Force Majeure.

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

PART IV

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

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

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

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

SECTION A - NOMINATIONS

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

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

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

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

SECTION B - OBLIGATION TO DELIVER

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

Unless otherwise authorized by the Company in writing, each Applicant of a Direct Purchase Bundled Service must meet its obligation to deliver gas to the Company on any given day by Firm Transportation. The Applicant must provide to the Company, at the time of execution of the Service Contract, sufficient proof of the Applicant's Firm Transportation arrangements.

Deleted: ¶

Formatted: Left

Formatted: Bullets and Numbering

Formatted: Left, Indent: Left: 18 pt

Formatted: Left

Formatted: Bullets and Numbering

Deleted: ¶

Deleted: ¶

Deleted: 8

Deleted: 07

Deleted: 8

Deleted: 01

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 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.

(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 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 average Ontario Transportation Service Credit over the contract year. 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

Formatted: Left

Formatted: Indent: Left: 7.2 pt, Hanging: 10.8 pt, Tabs: 18 pt, Left + Not at 10.8 pt

Deleted: 8

Deleted: 07

Deleted: 8

Deleted: 01

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.

Deleted:

Formatted: Left

Deleted: T-S

Formatted: Indent: Left: 10.75 pt

Deleted: ¶

Deleted: Banked Gas Account balances

Deleted: 8

Deleted: 07

Deleted: 8

Deleted: 01

RATE NUMBER: 1	RESIDENTIAL SERVICE

APPLICABILITY:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$16.00**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**14.4869 ¢/m³**
For the next 55 m³ per month	**13.9273 ¢/m³**
For the next 85 m³ per month	**13.4887 ¢/m³**
For all over 170 m³ per month	**13.1621 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.7802 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 6	GENERAL SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") for non-residential purposes.

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$55.00**
Delivery Charge per cubic metre	
For the first 500 m³ per month	**13.3159 ¢/m³**
For the next 1050 m³ per month	**11.5362 ¢/m³**
For the next 4500 m³ per month	**10.2904 ¢/m³**
For the next 7000 m³ per month	**9.4896 ¢/m³**
For the next 15250 m³ per month	**9.1337 ¢/m³**
For all over 28300 m³ per month	**9.0447 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.8980 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 9	CONTAINER SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") at which, such gas is authorized by the Company to be resold by filling pressurized containers.

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$232.64**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**15.4501 ¢/m³**
For all over 20,000 m³ per month	**14.7744 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 100	FIRM CONTRACT 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 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	**$121.23**
Delivery Charge	
Per cubic metre of Contract Demand	**8.1900 ¢/m³**
For the first 14,000 m³ per month	**5.1517 ¢/m³**
For the next 28,000 m³ per month	**3.7927 ¢/m³**
For all over 42,000 m³ per month	**3.2337 ¢/m³**
Gas Supply Load Balancing Charge	**5.5402 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.7362 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

RATE NUMBER: **100**

MINIMUM BILL:

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

10.6117 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

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	**$583.61**
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	**0.5529 ¢/m³**
For all over 1,000,000 m³ per month	**0.4029 ¢/m³**
Gas Supply Load Balancing Charge	**5.0683 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

RATE NUMBER: **110**

MINIMUM BILL:

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

5.5410 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 115	LARGE VOLUME LOAD FACTOR SERVICE

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$619.67**
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	**0.2940 ¢/m³**
For all over 1,000,000 m³ per month	**0.1940 ¢/m³**
Gas Supply Load Balancing Charge	**4.9335 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

RATE NUMBER: **115**

MINIMUM BILL:

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

5.1473 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

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	**9.0093 ¢/m³**
Direct Purchase Administration Charge	**$50.00**
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 = 0.9004 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 1.0805 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 1.0343 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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

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	**$114.54**	**$114.54**
Delivery Charge		
For the first 14,000 m³ per month	**6.7025 ¢/m³**	**2.0025 ¢/m³**
For the next 28,000 m³ per month	**5.5025 ¢/m³**	**1.3025 ¢/m³**
For all over 42,000 m³ per month	**5.1025 ¢/m³**	**1.1025 ¢/m³**
Gas Supply Load Balancing Charge	**4.8874 ¢/m³**	**4.8874 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.7057 ¢/m³**	**33.7057 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

RATE NUMBER **135**

SEASONAL CREDIT:

Rate per cubic metre of Mean Daily Volume from December to March	**$**	**0.77 /m^3**
Rate per cubic metre of Modified Mean Daily Volume for December	**$**	***0.77 /m^3***

SEASONAL OVERRUN CHARGE:

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

Seasonal Overrun Charges:

December and March	**23.1798 ¢/m³**
January and February	**57.9495 ¢/m³**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **8.3764 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 145	INTERRUPTIBLE SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service as ordered by the Company exercising its sole discretion. Any Applicant for service under this rate schedule must agree to transport a minimum annual volume of 340,000 cubic metres.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 72 hours prior to the time at which such curtailment or discontinuance is to commence. An Applicant may, by contract, agree to accept a shorter notice period.

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$122.53**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.8881 ¢/m³**
For the next 28,000 m³ per month	**1.5291 ¢/m³**
For all over 42,000 m³ per month	**0.9701 ¢/m³**
Gas Supply Load Balancing Charge	**5.3934 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.7875 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

Rate for 16 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.50 /m³**
Rate for 72 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.11 /m³**

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **8.2014 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 170	LARGE INTERRUPTIBLE SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas of not less than 30,000 cubic metres and a minimum annual volume of 5,000,000 cubic metres to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service when required by the Company. The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$277.09**
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	**0.5299 ¢/m³**
For all over 1,000,000 m³ per month	**0.3299 ¢/m³**
Gas Supply Load Balancing Charge	**5.1572 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

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

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

MINIMUM BILL:

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

5.6069 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: **200**	**WHOLESALE SERVICE**

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	**1.1359 ¢/m³**
Gas Supply Load Balancing Charge	**5.6049 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.6032 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**33.5855 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

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

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **6.6606 ¢/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, 2009 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the numbered rate schedule that specifies as the effective date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 300	FIRM OR INTERRUPTIBLE DISTRIBUTION SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation to a single Terminal Location of a specified maximum daily volume of natural gas. The Company reserves the right to limit service under this schedule to customers whose maximum contract demand does not exceed 600,000 m3. The Service under this rate requires Automatic Meter Reading (AMR) capability. Service under this schedule is firm unless a customer is currently served under interruptible distribution service or the Company, in its sole judgment, determines that existing delivery facilities cannot adequately serve the load on a firm basis.

The unitized Monthly Contract Demand Charge is also applicable to volumes delivered to any Applicant taking service under a Curtailment Delivered Supply contract with the Company. The unitized rate equals the applicable Monthly Contract Demand Charge times 12/365.

CHARACTER OF SERVICE:

The Service shall be continuous (firm) except for events specified in the Service Contract including force majeure. The Applicant is neither allowed to take a daily quantity of gas greater than the Contract Demand nor an hourly amount in excess of the Contract Demand divided by 24, without the Company's prior consent. Interruptible Distribution Service is provided on a best efforts basis subject to the events identified in the service contract including force majeure and, in addition, shall be subject to curtailment or discontinuance of service when the Company notifies the customer under normal circumstances 4 hours prior to the time that service is subject to curtailment or discontinuance. Under emergency conditions, the Company may curtail or discontinue service on one-hour notice. The Interruptible Service Customer is not allowed to exceed maximum hourly flow requirements as specified in Service Contract.

DISTRIBUTION RATES:

Monthly Customer Charge	**$500.00**
Monthly Contract Demand Charge Firm	**24.7336 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3554 ¢/m³**
Maximum Delivery Charge	**0.9758 ¢/m³**
Direct Purchase Administration Charge	**$50.00**
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 0.9004 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 1.0805 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 0.5738 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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

APPLICABILITY:

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

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

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

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

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

CHARACTER OF SERVICE:

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

The service is available on two bases:

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

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

RATE:

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

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0466 ¢/m³**
Monthly Storage *Deliverability* Demand Charge	**13.6672 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.5136 ¢/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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 316	GAS STORAGE SERVICE AT DAWN

APPLICABILITY:

This rate is available to any customer taking service under Distribution Rates 125 and 300. It requires a Service Contract that identifies the required storage space and deliverability. The customer shall maintain a positive balance of gas in storage at all times. ***In addition, the customer must arrange for pipeline delivery service from Dawn to the applicable Primary Delivery Area.***

This service is not a delivered service and is only available when the relevant pipeline confirms the delivery.

The maximum hourly injections / withdrawals shall equal 1/24 th of the daily Storage Demand.

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

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

CHARACTER OF SERVICE:

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

The service is nominated based on the available capacity and gas in storage up to the maximum contracted daily deliverability.

RATE:

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

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0466 ¢/m³**
Monthly Storage *Deliverability* Demand Charge	**4.3168 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.1672 ¢/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.

RATE NUMBER: **316**

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 TransCanad PipeLines (TCPL).

The customer may elect to nominate all or a portion of the available withdrawl 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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

RATE NUMBER: 320	BACKSTOPPING SERVICE

APPLICABILITY:

To any Applicant whose delivery of natural gas to the Company for transportation to a Terminal Location has been interrupted prior to the delivery of such gas to the Company.

CHARACTER OF SERVICE:

The volume of gas available for backstopping in any day shall be determined by the Company exercising its sole discretion. If the aggregate daily demand for service under this Rate Schedule exceeds the supply available for such day, the available supply shall be allocated to firm service customers on a first requested basis and any balance shall be available to interruptible customers on a first requested basis.

RATE:

The rates applicable in the circumstances contemplated by this Rate Schedule, in lieu of the Gas Supply Charges specified in any of the Company's other Rate Schedules pursuant to which the Applicant is taking service, shall be as follows:

	Billing Month January to December
Gas Supply Charge	
Per cubic metre of gas sold	**39.0903 ¢/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, 2009 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates as the Board Order, EB-2008-0263, effective October 1, 2008.

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 $/10³m³	**Pool Storage $/10³m³**
Demand Charge for:		
Annual Turnover Volume	**0.1838**	**0.2185**
Maximum Daily Withdrawal Volume	**16.6188**	**19.8179**
Commodity Charge	**1.5051**	**0.5898**

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	**2.4264**	**0.5464**
Unauthorized	**-**	**219.3685**
Pool Storage		
Authorized	**2.8840**	**0.6515**
Unauthorized	**-**	**261.5969**

(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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

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	
	$/10³m³	$/10³m³	$/10³m³
Monthly Demand Charge per unit of Annual Turnover Volume:			
Minimum	**0.4023**	**0.4023**	**-**
Maximum	**2.0115**	**2.0115**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**36.4368**	**29.1494**	**-**
Maximum	**182.1839**	**145.7471**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**2.0949**	**2.0949**	**0.9219**
Maximum	**10.4745**	**10.4745**	**41.6932**

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	Interruptible	
	$/10³m³	$/10³m³	$/10³m³
Authorized Overrun			
Annual Turnover Volume			
Negotiable, not to exceed:	**41.6932**	**41.6932**	**41.6932**
Authorized Overrun			
Daily Injection/Withdrawal			
Negotiable, not to exceed:	**41.6932**	**41.6932**	**41.6932**
Unauthorized Overrun			
Annual Turnover Volume			
Excess Storage Balance			
September 1 - November 30	**416.9320**	**416.9320**	**416.9320**
December 1 - October 31	**41.6932**	**41.6932**	**41.6932**
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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

APPLICABILITY:

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

CHARACTER OF SERVICE:

Service under this rate is for firm transportation service as may be available from time to time.

RATE:

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

	Firm $/10³m³	Interruptible $/10³m³
Monthly Demand Charge per unit of Maximum Contracted Daily Delivery:	**5.1620**	**-**
Commodity Charge per unit of gas delivered:	**-**	**0.2040**

MINIMUM BILL:

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

TERMS AND CONDITIONS OF SERVICE:

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

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

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

AREAS OF CAPACITY CONSTRAINT

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:

Base Charge	$50.00 per month
Maximum Charge	$815.00 per month
Account Charge	
New Accounts	$0.50 per month per account
Renewal Accounts	$0.15 per month per account

The above Basic Charge shall be increased up to the maximum charge, by the new account charge for each new account and by the Renewal Account charge for each renewal account in a Direct Purchase Contract.

T-SERVICE CREDIT:

In T-Service Arrangements excluding Ontario ABC-T arrangements, between the Company and an Applicant, and with a T-Service Arrangement and a contractually specified Point of Acceptance as indicated below, the Company shall pay or charge the Applicant the Transportation Service Credit or Debit shown for any volumes of natural gas owned by the Applicant and received by the Company at the Point of Acceptance. The ability of the Company to accept deliveries under FT-type arrangements at Dawn is constrained and the availability of this service is at the Company's sole discretion.

TOLLS CREDIT	**Type of Arrangement**	
Point of Acceptance	Firm Transportation (FT)	Firm Service Tendered (FST)
Western Canada	0.0000 ¢/m³	0.0000 ¢/m³
CDA, EDA	4.8874 ¢/m³	0.0000 ¢/m³
Dawn	4.6406 ¢/m³	0.0000 ¢/m³
Intra-Alberta	-0.5514 ¢/m³	N/A

Effective February 1, 2001, in Ontario ABC-T arrangements with a contractually specified Point of Acceptance in the CDA and/or EDA, the toll credit shall equal the Eastern Zone Firm Transportation tolls approved by the National Energy Board for TCPL at a 100% load factor.

TCPL FT CAPACITY TURNBACK:

APPLICABILITY:

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

TERMS AND CONDITIONS OF SERVICE:

1. The Company will accommodate TCPL FT capacity turnback from customers to the extent that the Company is allowed to turnback FT capacity to TCPL.

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

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

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

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

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

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

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

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

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

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

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

    or

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

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

RIDER: B	BUY / SELL SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who entered into a Gas Purchase Agreement with the Company, prior to April 1, 1999, to sell to the Company a supply of natural gas.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Base Charge	$50.00	per month
Maximum Charge	$815.00	per month
Account Charge		
New Accounts	$0.50	per month per account
Renewal Accounts	$0.15	per month per account

The above Basic Charge shall be increased up to the maximum charge, by the new account charge for each new account and by the Renewal Account charge for each renewal account in a Direct Purchase Contract.

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, 2009. This rate schedule is effective January 1, 2009 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2008 and that indicates, as the Board Order, EB-2008-0263, effective October 1, 2008.

RIDER: C	GAS COST ADJUSTMENT RIDER

The following adjustment is applicable to all gas sold or delivered during the period of January1, 2009 to December 31, 2009.

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

RIDER: E	REVENUE ADJUSTMENT RIDER

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

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

RIDER: F	ATMOSPHERIC PRESSURE FACTORS

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

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

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

RIDER: **G**

Safety Inspection	
Inspection Charge ***For inspection of gas appliances; the Company provides only <u>one</u> inspection free of charge, upon first time introductionof 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***

RIDER: H	BALANCING SERVICE RIDER

APPLICABILITY:

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

ENHANCED TITLE TRANSFER SERVICE:

In any Gas Transportation 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	$1.0474	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-2008-0219 RATES				
ITEM NO.	RATE NO.	DISTRIBUTION	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL
1.	1	691,795	224,899	41,896	978,473	1,937,062
2.	6	308,902	218,908	39,117	616,664	1,183,591
3.	9	353	128	0	725	1,206
4.	100	0	0	0	0	0
5.	110	14,040	33,771	1,250	24,029	73,090
6.	115	6,633	26,224	247	1,492	34,596
7.	125	6,588	0	0	0	6,588
8.	135	944	2,841	(490)	1,118	4,414
9.	145	5,261	11,049	318	7,607	24,236
10.	170	4,981	29,417	(5,632)	18,913	47,679
11.	200	3,341	7,397	990	39,937	51,666
12.	300	510	0	0	0	510
13.	SUB-TOTAL	1,043,348	554,634	77,696	1,688,959	3,364,637
14.	STORAGE	1,800	0	0	0	1,800
15.	DPAC	1,561	0	0	0	1,561
16.	TOTAL	1,046,709	554,634	77,696	1,688,959	3,367,998

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
					GAS SUPPLY TRANSPORTATION			GAS SUPPLY LOAD BALANCING			GAS SUPPLY COMMODITY			
ITEM	RATE	DISTRIBUTION												TOTAL
NO.	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	4,601,560	691,795	15.03	4,601,560	224,899	4.89	4,601,560	41,896	0.91	2,896,586	978,473	33.78	1,937,062
2.	6	4,478,987	308,902	6.90	4,478,987	218,908	4.89	4,478,987	39,117	0.87	1,819,176	616,664	33.90	1,183,591
3.	9	2,618	353	13.49	2,618	128	4.89	2,618	0	0.00	2,158	725	33.60	1,206
4.	100	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0
5.	110	690,968	14,040	2.03	690,968	33,771	4.89	690,968	1,250	0.18	71,509	24,029	33.60	73,090
6.	115	536,550	6,633	1.24	536,550	26,224	4.89	536,550	247	0.05	4,440	1,492	33.60	34,596
7.	125	0	6,588	0.00	0	0	0.00	0	0	0.00	0	0	0.00	6,588
8.	135	58,131	944	1.62	58,131	2,841	4.89	58,131	(490)	(0.84)	3,317	1,118	33.71	4,414
9.	145	226,075	5,261	2.33	226,075	11,049	4.89	226,075	318	0.14	22,515	7,607	33.79	24,236
10.	170	601,882	4,981	0.83	601,882	29,417	4.89	601,882	(5,632)	(0.94)	56,284	18,913	33.60	47,679
11.	200	151,354	3,341	2.21	151,354	7,397	4.89	151,354	990	0.65	118,849	39,937	33.60	51,666
12.	300	51,702	510	0.00	0	0	0.00	0	0	0.00	0	0	0.00	510
13	SUB-TOTAL	11,399,828	1,043,348	9.15	11,348,126	554,634	4.8874	11,348,126	77,696	0.68	4,994,836	1,688,959	33.81	3,364,637
14.	STORAGE	N/A	1,800	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,800
15.	DPAC	N/A	1,561	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,561
16.	TOTAL	11,399,828	1,046,709	9.15	11,348,126	554,634	4.89	11,348,126	77,696	0.68	4,994,836	1,688,959	33.81	3,367,998

REVENUE - PROPOSED METHODOLOGY BY RATE CLASS

Item No.	Rate No.	Col. 1	Col. 2 REVENUE -EB-2008-0219 RATES Proposed Revenue ($000)	Col. 3 Unbilled Revenue ($000)	Col. 4 Total ($000)
1.	1		1,937,062	1,788	1,938,851
2.	6		1,183,591	(4,319)	1,179,272
3.	9		1,206	0	1,206
4.	100		0	0	0
5.	110		73,090	(131)	72,958
6.	115		34,596	(202)	34,393
7.	125		6,588	0	6,588
8.	135		4,414	2	4,415
9.	145		24,236	(205)	24,031
10.	170		47,679	(192)	47,487
11.	200		51,666	0	51,666
12.	300		510	0	510
13.	SUB-TOTAL		3,364,637	(3,259)	3,361,378
14.	STORAGE		1,800	0	1,800
15.	DPAC		1,561	0	1,561
16.	TOTAL		3,367,998	(3,259)	3,364,740

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

Item No.	Rate No.	Col. 1	Col. 2 Rate Block m^3	Col. 3 Interim EB-2008-0263 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2008-0219 cents *
	RATE 1					
1.01		Customer Charge		$14.00	$2.00	$16.00
1.02		Delivery Charge	first 30	9.4389	(0.7499)	8.6890
1.03			next 55	8.8309	(0.7016)	8.1294
1.04			next 85	8.3545	(0.6637)	7.6908
1.05			over 170	7.9997	(0.6355)	7.3642
1.06		Gas Supply Load Balancing		1.0267	(0.1162)	0.9105
1.07		Gas Supply Transportation		4.9187	(0.0312)	4.8874
1.08		Gas Supply Commodity - System		33.7551	0.0251	33.7802
1.09		Gas Supply Commodity - Buy/Sell		33.7366	0.0259	33.7625
	RATE 6					
2.01		Customer Charge		$50.00	$5.00	$55.00
2.02		Delivery Charge	First 500	7.4872	0.0680	7.5552
2.03			Next 1050	5.7235	0.0520	5.7755
2.04			Next 4500	4.4889	0.0407	4.5297
2.05			Next 7000	3.6953	0.0335	3.7289
2.06			Next 15250	3.3427	0.0303	3.3730
2.07			Over 28300	3.2544	0.0295	3.2840
2.08		Gas Supply Load Balancing		1.0425	(0.1692)	0.8733
2.09		Gas Supply Transportation		4.9187	(0.0312)	4.8874
2.10		Gas Supply Commodity - System		33.8781	0.0199	33.8980
2.11		Gas Supply Commodity - Buy/Sell		33.8596	0.0207	33.8803
	RATE 9					
3.01		Customer Charge		$232.01	$0.63	$232.64
3.02		Delivery Charge	first 20000	10.5430	0.0197	10.5627
3.03			over 20000	9.8685	0.0185	9.8870
3.04		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.05		Gas Supply Transportation		4.9187	(0.0312)	4.8874
3.06		Gas Supply Commodity - System		33.5922	0.0110	33.6032
3.07		Gas Supply Commodity - Buy/Sell		33.5737	0.0118	33.5855
	RATE 100					
4.01		Customer Charge		$118.97	$2.26	$121.23
4.02		Demand Charge (Cents/Month/m^3)		8.1900	0.0000	8.1900
4.03		Delivery Charge	first 14,000	5.0637	0.0881	5.1517
4.04			next 28,000	3.7047	0.0881	3.7927
4.05			over 42,000	3.1457	0.0881	3.2337
4.06		Gas Supply Load Balancing		0.7501	(0.1692)	0.6528
4.07		Gas Supply Transportation		4.9187	(0.0312)	4.8874
4.08		Gas Supply Commodity - System		33.7164	0.0199	33.7362
		Gas Supply Commodity - Buy/Sell		33.6979	0.0207	33.7177
	RATE 110					
5.01		Customer Charge		$572.75	$10.86	$583.61
5.02		Demand Charge (Cents/Month/m^3)		22.9100	0.0000	22.9100
5.03		Delivery Charge	first 1,000,000	0.5191	0.0338	0.5529
5.04			over 1,000,000	0.3691	0.0338	0.4029
5.05		Load Balancing Commodity		0.2078	(0.0270)	0.1808
5.06		Gas Supply Transportation		4.9187	(0.0312)	4.8874
5.07		Gas Supply Commodity - System		33.5922	0.0110	33.6032
5.08		Gas Supply Commodity - Buy/Sell		33.5737	0.0118	33.5855

NOTE : * Cents unless otherwise noted.

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m^3	Col. 3 Interim EB-2008-0263 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2008-0219 cents *
	RATE 115					
1.01		Customer Charge		$609.16	$10.51	$619.67
1.02		Demand Charge (Cents/Month/m^3)		24.3600	0.0000	24.3600
1.03		Delivery Charge	first 1,000,000	0.2737	0.0202	0.2940
1.04			over 1,000,000	0.1737	0.0202	0.1940
1.05		Load Balancing Commodity		0.0636	(0.0175)	0.0461
1.06		Gas Supply Transportation		4.9187	(0.0312)	4.8874
1.07		Gas Supply Commodity - System		33.5922	0.0110	33.6032
1.08		Gas Supply Commodity - Buy/Sell		33.5737	0.0118	33.5855
	RATE 125					
2.01		Customer Charge		$ 500.00	$0.00	$ 500.00
2.02		Delivery Charge (Cents/Month/m^3 of Contract Dmnd)		9.0032	0.0061	9.0093
	RATE 135	DEC - MAR				
3.00		Customer Charge		$112.84	$1.70	$114.54
3.01		Delivery Charge	first 14,000	6.6799	0.0226	6.7025
3.02			next 28,000	5.4799	0.0226	5.5025
3.03			over 42,000	5.0799	0.0226	5.1025
3.04		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.05		Gas Supply Transportation		4.9187	(0.0312)	4.8874
3.06		Gas Supply Commodity - System		33.6805	0.0252	33.7057
3.07		Gas Supply Commodity - Buy/Sell		33.6620	0.0260	33.6880
	RATE 135	APR - NOV				
3.08		Customer Charge		$112.84	$1.70	$114.54
3.09		Delivery Charge	first 14,000	1.9799	0.0226	2.0025
3.10			next 28,000	1.2799	0.0226	1.3025
3.11			over 42,000	1.0799	0.0226	1.1025
3.12		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.13		Gas Supply Transportation		4.9187	(0.0312)	4.8874
3.14		Gas Supply Commodity - System		33.6805	0.0252	33.7057
3.15		Gas Supply Commodity - Buy/Sell		33.6620	0.0260	33.6880
	RATE 145					
4.00		Customer Charge		$121.47	$1.06	$122.53
4.01		Demand Charge (Cents/Month/m^3)		8.2300	-	8.2300
4.02		Delivery Charge	first 14,000	2.8682	0.0199	2.8881
4.03			next 28,000	1.5092	0.0199	1.5291
4.04			over 42,000	0.9502	0.0199	0.9701
4.05		Gas Supply Load Balancing		0.4958	0.0102	0.5060
4.06		Gas Supply Transportation		4.9187	(0.0312)	4.8874
4.07		Gas Supply Commodity - System		33.7084	0.0791	33.7875
4.08		Gas Supply Commodity - Buy/Sell		33.6899	0.0799	33.7698
	RATE 170					
5.00		Customer Charge		$272.53	$4.56	$277.09
5.01		Demand Charge (Cents/Month/m^3)		4.0900	0.0000	4.0900
5.02		Delivery Charge	first 1,000,000	0.5162	0.0138	0.5299
5.03			over 1,000,000	0.3162	0.0138	0.3299
5.04		Gas Supply Load Balancing		0.2739	(0.0041)	0.2698
5.05		Gas Supply Transportation		4.9187	(0.0312)	4.8874
5.06		Gas Supply Commodity - System		33.5922	0.0110	33.6032
5.07		Gas Supply Commodity - Buy/Sell		33.5737	0.0118	33.5855

NOTE : * Cents unless otherwise noted.

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m^3	Col. 3 Interim EB-2008-0263 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2008-0219 cents *	
	RATE 200						
1.00		Customer Charge		$0.00	$0.00	$0.00	
1.01		Demand Charge (Cents/Month/m^3)		14.7000	0.0000	14.7000	
1.02		Delivery Charge		1.0371	0.0987	1.1359	
1.03		Gas Supply Load Balancing		0.7856	(0.0681)	0.7175	
1.04		Gas Supply Transportation		4.9187	(0.0312)	4.8874	
1.05		Gas Supply Commodity - System		33.5922	0.0110	33.6032	
1.06		Gas Supply Commodity - Buy/Sell		33.5737	0.0118	33.5855	
	RATE 300	FIRM SERVICE					
2.00		Monthly Customer Charge		$500.00	$0.00	$500.00	
2.01		Demand Charge (Cents/Month/m^3)		24.7168	0.0168	24.7336	
		INTERRUPTIBLE SERVICE					
2.02		Minimum Delivery Charge (Cents/Month/m^3)		0.3556	(0.0002)	0.3554	
2.03		Maximum Delivery Charge (Cents/Month/m^3)		0.9751	0.0007	0.9758	
	RATE 315						
		Monthly Customer Charge		$150.00	$0.00	$150.00	
3.00		Space Demand Chg (Cents/Month/m^3)		0.0364	0.0102	0.0466	
3.01		Deliverability/Injection Demand Chg (Cents/Month/m^3)		13.5776	0.0895	13.6672	
3.02		Injection & Withdrawal Chg (Cents/Month/m^3)		0.4486	0.0650	0.5136	(1)
	RATE 320						
4.00		Backstop	All Gas Sold	39.1009	(0.0106)	39.0903	
	RATE 316						
		Monthly Customer Charge		$150.00	$0.00	$150.00	
5.00		Space Demand Chg (Cents/Month/m^3)		0.0364	0.0102	0.0466	
5.01		Deliverability/Injection Demand Chg (Cents/Month/m^3)		3.5153	0.8015	4.3168	
5.02		Injection & Withdrawal Chg (Cents/Month/m^3)		0.1681	(0.0008)	0.1672	

NOTE : * Cents unless otherwise noted.

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m^3	Col. 3 Interim EB-2008-0263 cents *	Col. 4 Change cents *	Col. 5 EB-2008-0219 cents *
	RATE 325					
		Transmission & Compression				
1.00		Demand Charge - ATV ($/Month/$10^3$ m^3)		0.1766	0.0072	0.1838
1.01		Demand Charge - Daily Wdrl. ($/Month/$10^3$ m^3)		15.9648	0.6540	16.6188
1.02		Commodity Charge		1.5030	0.0021	1.5051
		Storage				
1.03		Demand Charge - ATV ($/Month/10*3 m^3)		0.2095 (2)	0.0090	0.2185
1.04		Demand Charge - Daily Wdrl. ($/Month/$10^3$ m^3)		19.0044 (2)	0.8135	19.8179
1.05		Commodity Charge		0.5930	(0.0032)	0.5898
		(2) Note: These are UNBUNDLED Rates				
	RATE 330	Storage Service - Firm				
		Demand Charge ($/Month/$10^3$ m^3 of ATV)				
2.00		Minimum		0.3861	0.0162	0.4023
2.01		Maximum		1.9305	0.0810	2.0115
		Demand Charge ($/Month/$10^3$ m^3 of Daily Withdrawal)				
2.02		Minimum		34.9692	1.4675	36.4368
2.03		Maximum		174.8462	7.3377	182.1839
		Commodity Charge				
2.04		Minimum		2.0960	(0.0011)	2.0949
2.05		Maximum		10.4800	($0.0055)	10.4745
		Storage Service - Interruptible				
		Demand Charge ($/Month/$10^3$ m^3 of ATV)				
2.06		Minimum		0.3861	0.0162	0.4023
2.07		Maximum		1.9305	0.0810	2.0115
		Demand Charge ($/Month/$10^3$ m^3 of Daily Withdrawal)				
2.08		Minimum		27.9754	1.1740	29.1494
2.09		Maximum		139.8769	$5.8702	145.7471
		Commodity Charge				
2.10		Minimum		2.0960	(0.0011)	2.0949
2.11		Maximum		10.4800	(0.0055)	10.4745
		Storage Service - Off Peak				
		Commodity Charge				
2.12		Minimum		0.9155	0.0064	0.9219
2.13		Maximum		40.4413	1.2519	41.6932
	RATE 331	Tecumseh Transmission Service				
		Firm				
		Demand Charge ($/Month/$10^3$ m^3 of				
3.00		Maximum Contracted Daily Delivery)		4.8310	0.3310	5.1620
		Interruptible				
3.01		Commodity Charge ($/$10^3 m^3$ of gas delivered)		0.1910	0.0130	0.2040

NOTE : * Cents unless otherwise noted.

CALCULATION OF GAS SUPPLY CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF GAS SUPPLY CHARGE												
	GAS SUPPLY COSTS ($000)												
1.1	Annual Commodity	1,675,819	971,835	610,352	724	-	23,992	1,490	1,113	7,554	18,884	39,875	
1.2	Bad Debt Commodity	10,533	5,126	5,363	-	-	-	-	3	41	-	-	
1.3	System Gas Fee	885	513	322	0	-	13	1	1	4	10	21	
1.4	Return on Rate Base - Working Cash	1,722	999	627	1	-	25	2	1	8	19	41	
1	Total Commodity Costs	1,688,960	978,472	616,665	725	-	24,029	1,492	1,118	7,607	18,913	39,937	
	VOLUMES (10^3 m^3)												
2.1	System and Buy/Sell Volumes	4,994,836	2,896,586	1,819,176	2,158	-	71,509	4,440	3,317	22,515	56,284	118,849	
2.2	System Volumes	4,994,836	2,896,586	1,819,176	2,158	-	71,509	4,440	3,317	22,515	56,284	118,849	
	GAS SUPPLY CHARGE SYSTEM (¢/m^3)												
3.1	Annual Commodity	33.5510	33.5510	33.5510	33.5510	-	33.5510	33.5510	33.5510	33.5510	33.5510	33.5510	1.1 / 2.1
3.2	Bad Debt Commodity	0.2109	0.1770	0.2948	-	-	-	-	0.1025	0.1843	-	-	1.2 / 2.1
3.3	System Gas Fee	0.0177	0.0177	0.0177	0.0177	-	0.0177	0.0177	0.0177	0.0177	0.0177	0.0177	1.3 / 2.2
3.4	Return on Rate Base - Working Cash	0.0345	0.0345	0.0345	0.0345	-	0.0345	0.0345	0.0345	0.0345	0.0345	0.0345	1.4 / 2.1
3	System Gas Supply Charge	33.8141	33.7802	33.8980	33.6032	-	33.6032	33.6032	33.7057	33.7875	33.6032	33.6032	
	GAS SUPPLY CHARGE BUY/SELL(¢/m3)												
4.1	Annual Commodity	33.5510	33.5510	33.5510	33.5510	-	33.5510	33.5510	33.5510	33.5510	33.5510	33.5510	1.1 / 2.1
4.2	Bad Debt Commodity	0.2109	0.1770	0.2948	-	-	-	-	0.1025	0.1843	-	-	1.2 / 2.1
4.3	Return on Rate Base - Working Cash	0.0345	0.0345	0.0345	0.0345	-	0.0345	0.0345	0.0345	0.0345	0.0345	0.0345	1.4 / 2.1
4	Buy/Sell Gas Supply Charge	33.7964	33.7625	33.8803	33.5855	-	33.5855	33.5855	33.6880	33.7698	33.5855	33.5855	

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	11,218	5,816	5,201	0	0	80	20	-	-	-	100	
5.2	Seasonal	24,868	11,940	11,224	-	-	387	75	-	379	537	326	
5.3	Return on Rate Base - Gas in Inventory	50,278	24,140	22,692	-	-	783	152	-	765	1,086	659	
5	Total Load Balancing	86,363	41,896	39,117	0	0	1,250	247	-	1,144	1,624	1,086	
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,348,126	4,601,560	4,478,987	2,618	-	690,968	536,550	58,131	226,075	601,882	151,354	
7	ANNUAL LOAD BALANCING CHARGE (¢/m3)		0.9105	0.8733	0.0009	-	0.1808	0.0461	-	0.5060	0.2698	0.7175	5.0 / 6
	DERIVATION OF TRANSPORTATION CHARGES												
8	Pipeline Annual incl. some M12 (upstream	554,634	224,899	218,908	128	-	33,771	26,224	2,841	11,049	29,417	7,397	
	VOLUMES (10^3 m^3)												
9	Annual Deliveries	11,348,126	4,601,560	4,478,987	2,618	-	690,968	536,550	58,131	226,075	601,882	151,354	
10	PROPOSED TRANSPORTATION CHARGE (¢/m^3)		4.8874	4.8874	4.8874	4.8874	4.8874	4.8874	4.8874	4.8874	4.8874	4.8874	

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

RATE 135		
Seasonal Credits Applicable to Rate 135	$	(490)
Annual Volume (103 m3)		58,131
Mean Daily Volume (103 m3)		159
Annual Seasonal Credits	$	(3.08)
Payable from December to March	$	(0.77)
RATE 145		
Seasonal Credits Applicable to Rate 145	$	(826)
Annual Volume (103 m3)		226,075
Mean Daily Volume (103 m3)		
16 Hours		352
72 Hours		271
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	$	(704.02)
72 Hours	$	(121.78)
RATE 170		
Seasonal Credits Applicable to Rate 170	$	(7,256)
Annual Volume (103 m3)		601,882
Mean Daily Volume (103 m3)		1,649
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)
RATE 200		
Seasonal Credits Applicable to Rate 200	$	(95)
Annual Volume (103 m3)		7,917
Mean Daily Volume (103 m3)		22
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m^3	Col. 2 EB-2008-0219 Bills & Volumes $10^3 m^3$	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 1				
1.1	Customer Charge	Bills	20,965,129	$16.00	335,442
1.2	Delivery Charge	first 30	596,244	8.6890	51,808
1.3		next 55	865,328	8.1294	70,346
1.4		next 85	942,995	7.6908	72,523
1.5		over 170	2,196,992	7.3642	161,790
1.	Total Distribution Charge		4,601,560		691,909
2.1	Gas Supply Load Balancing		4,601,560	0.9105	41,896
2.2	Gas Supply Transportation		4,601,560	4.8874	224,899
3.1	Gas Supply Commodity - System		2,896,586	33.7802	978,473
3.2	Gas Supply Commodity - Buy/Sell		0	33.7625	0
3.	Total Gas Supply Charge		2,896,586		978,473
4.1	TOTAL DISTRIBUTION		4,601,560		691,909
4.2	TOTAL GAS SUPPLY LOAD BALANCINC		4,601,560		266,795
4.3	TOTAL GAS SUPPLY COMMODITY		2,896,586		978,473
4.	TOTAL RATE 1		4,601,560		1,937,177
5.	Adj. Factor	0.9999			
6.	ADJUSTED REVENUE				1,937,062

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m^3	Col. 2 EB-2008-0219 Bills & Volumes $10^3 m^3$	Col. 3 EB-2008-0219 Rate cents*	Col. 4 EB-2008-0219 Revenues $000
	RATE 6				
1.1	Customer Charge	Bills	1,905,194	$55.00	104,786
1.2	Delivery Charge	First 500	538,315	7.5552	40,671
1.3		Next 1050	642,051	5.7755	37,082
1.4		Next 4500	1,155,669	4.5297	52,348
1.5		Next 7000	710,156	3.7289	26,481
1.6		Next 15250	620,099	3.3730	20,916
1.7		Over 28300	812,698	3.2840	26,689
1.	Total Distribution Charge		4,478,987		308,971
2.1	Gas Supply Load Balancing		4,478,987	0.8733	39,117
2.2	Gas Supply Transportation		4,478,987	4.8874	218,908
3.1	Gas Supply Commodity - System		1,819,176	33.8980	616,664
3.2	Gas Supply Commodity - Buy/Sell		0	33.8803	0
3.	Total Gas Supply Charge		1,819,176		616,664
4.1	TOTAL DISTRIBUTION		4,478,987		308,971
4.2	TOTAL GAS SUPPLY LOAD BALANCING		4,478,987		258,025
4.3	TOTAL GAS SUPPLY COMMODITY		1,819,176		616,664
4.	TOTAL RATE 6		4,478,987		1,183,660
5.	Adj. Factor	1.000			
6.	ADJUSTED REVENUE				1,183,591

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2008-0219		
Item No.		Rate Block m^3	Bills & Volumes 10^3 m^3	Rate cents*	Revenues $000
	RATE 9				
1.1	Customer Charge	Bills	336	$232.64	78
1.2	Delivery Charge	first 20000	2,401	10.5627	254
1.3		over 20000	217	9.8870	21
1.	Total Distribution Charge		2,618		353
2.1	Gas Supply Load Balancing		2,618	0.0000	0
2.2	Gas Supply Transportation		2,618	4.8874	128
3.1	Gas Supply Commodity - System		2,158	33.6032	725
3.2	Gas Supply Commodity - Buy/Sell		0	33.5855	0
3.	Total Gas Supply Charge		2,158		725
4.1	TOTAL DISTRIBUTION		2,618		353
4.2	TOTAL GAS SUPPLY LOAD BALANCINC		2,618		128
4.3	TOTAL GAS SUPPLY COMMODITY		2,158		725
4	TOTAL RATE 9		2,618		1,206

			EB-2008-0219		
		Rate Block m^3	Contracts & Volumes 10^3 m^3	Rate cents*	Revenues $000
	RATE 100				
1.1	Customer Charge	Contracts	0	$121.23	0
1.2	Demand Charge		0	8.19	0
1.3	Delivery Charge	first 14,000	0	5.1517	0
1.4		next 28,000	0	3.7927	0
1.5		over 42,000	0	3.2337	0
1	Total Distribution Charge		0		0
2.1	Gas Supply Load Balancing		0	0.6528	0
2.2	Gas Supply Transportation		0	4.8874	0
3.1	Gas Supply Commodity - System		0	33.7362	0
3.2	Gas Supply Commodity - Buy/Sell		0	33.7177	0
3	Total Gas Supply Charge		0		0
4.1	TOTAL DISTRIBUTION		0		0
4.2	TOTAL GAS SUPPLY LOAD BALANCINC		0		0
4.3	TOTAL GAS SUPPLY COMMODITY		0		0
4	TOTAL RATE 100		0		0

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2008-0219		
Item No.		Rate Block m^3	Contracts & Volumes $10^3 m^3$	Rate cents*	Revenues $000
	RATE 110				
1.1	Customer Charge	Contracts	2,891	$583.61	1,687
1.2	Demand Charge		38,182	22.9100	8,748
1.3	Delivery Charge	first 1,000,000	547,461	0.5529	3,027
1.4		over 1,000,000	143,507	0.4029	578
1.	Total Distribution Charge		690,968		14,040
2.1	Load Balancing Demand		38,182	0.0000	0
2.2	Load Balancing Commodity		690,968	0.1808	1,250
2.3	Gas Supply Transportation		690,968	4.8874	33,771
2.	Total Gas Supply Load Balancing				35,020
3.1	Gas Supply Commodity - System		71,509	33.6032	24,029
3.2	Gas Supply Commodity - Buy/Sell		0	33.5855	0
3.	Total Gas Supply Charge		71,509		24,029
4.1	TOTAL DISTRIBUTION		690,968		14,040
4.2	TOTAL GAS SUPPLY LOAD BALANCING		690,968		35,020
4.3	TOTAL GAS SUPPLY COMMODITY		71,509		24,029
4.	TOTAL RATE 110		690,968		73,091

			EB-2008-0219		
		Rate Block m^3	Contracts & Volumes $10^3 m^3$	Rate cents*	Revenues $000
	RATE 115				
6.6	Customer Charge	Contracts	480	$619.67	297
6.2	Demand Charge		20,810	24.3600	5,069
6.3	Delivery Charge	first 1,000,000	225,219	0.2940	662
6.4		over 1,000,000	311,331	0.1940	604
6	Total Distribution Charge		536,550		6,633
7.1	Load Balancing Demand		20,810	0.0000	0
7.7	Load Balancing Commodity		536,550	0.0461	247
7.3	Gas Supply Transportation		536,550	4.8874	26,224
7	Total Gas Supply Load Balancing				26,471
8.1	Gas Supply Commodity - System		4,440	33.6032	1,492
8.2	Gas Supply Commodity - Buy/Sell		0	33.5855	0
8.	Total Gas Supply Charge		4,440		1,492
9.1	TOTAL DISTRIBUTION		536,550		6,633
9.2	TOTAL GAS SUPPLY LOAD BALANCING		536,550		26,471
9.3	TOTAL GAS SUPPLY COMMODITY		4,440		1,492
9.	TOTAL RATE 115		536,550		34,595

NOTE * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2008-0219		
Item No.		Rate Block m^3	Contracts & Volumes $10^3 m^3$	Rate cents*	Revenues $000
	RATE 125				
1.1	Customer Charge		12	$ 500.00	6
1.2	Demand Charge		73,053	9.0093	6,582
1.	Total Distribution Charge		73,053		6,588

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2008-0219		
Item No.		Rate Block m^3	Contracts & Volumes $10^3 m^3$	Rate cents*	Revenues $000
	RATE 135				
	DEC to MAR				
1.1	Customer Charge	Contracts	152	$114.54	17
1.2	Delivery Charge	first 14,000	615	6.7025	41
1.3		next 28,000	1,048	5.5025	58
1.4		over 42,000	2,985	5.1025	152
1.	Total Distribution Charge		4,648		269
2.1	Gas Supply Load Balancing		4,648	0.0000	0
2.2	Gas Supply Transportation		4,648	4.8874	227
2.3	Seasonal Credit				(490)
3.1	Gas Supply Commodity - System		100	33.7057	34
3.2	Gas Supply Commodity - Buy/Sell		0	33.6880	0
3.	Total Gas Supply Charge		100		34
4.	SUB-TOTAL WINTER				39
	APR to NOV				
5.1	Customer Charge	Contracts	304	$114.54	35
5.2	Delivery Charge	first 14,000	4,004	2.0025	80
5.3		next 28,000	7,695	1.3025	100
5.4		over 42,000	41,783	1.1025	461
5.	Total Distribution Charge		53,483		676
6.1	Gas Supply Load Balancing		53,483	0.0000	0
6.2	Gas Supply Transportation		53,483	4.8874	2,614
7.1	Gas Supply Commodity - System		3,217	33.7057	1,084
7.2	Gas Supply Commodity - Buy/Sell		0	33.6880	0
7.	Total Gas Supply Charge		3,217		1,084
8.	SUB-TOTAL SUMMER				4,374
9.1	TOTAL DISTRIBUTION		58,131		944
9.2	TOTAL GAS SUPPLY LOAD BALANCING		58,131		2,351
9.3	TOTAL GAS SUPPLY COMMODITY		3,317		1,118
9.	TOTAL RATE 135		58,131		4,414

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2008-0219		
Item No.		Rate Block m^3	Contracts & Volumes $10^3 m^3$	Rate cents*	Revenues $000
	RATE 145				
1.1	Customer Charge	Contracts	2,232	$122.53	273
1.2	Demand Charge		23,594	8.2300	1,942
1.2	Delivery Charge	first 14,000	29,745	2.8881	859
1.3		next 28,000	50,472	1.5291	772
1.4		over 42,000	145,857	0.9701	1,415
1.	Total Distribution Charge		226,075		5,261
2.1	Gas Supply Load Balancing		226,075	0.5060	1,144
2.2	Gas Supply Transportation		226,075	4.8874	11,049
2.3	Curtailment Credit				(826)
3.1	Gas Supply Commodity - System		22,515	33.7875	7,607
3.2	Gas Supply Commodity - Buy/Sell		0	33.7698	0
3.	Total Gas Supply Charge		22,515		7,607
4.1	TOTAL DISTRIBUTION		226,075		5,261
4.2	TOTAL GAS SUPPLY LOAD BALANCINC		226,075		11,367
4.3	TOTAL GAS SUPPLY COMMODITY		22,515		7,607
4.	TOTAL RATE 145		226,075		24,236

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2008-0219		
		Rate Block m^3	Contracts & Volumes $10^3 m^3$	Rate cents*	Revenues $000
	RATE 170				
6.6	Customer Charge	Contracts	468	$277.09	130
6.2	Demand Charge		52,544	4.0900	2,149
6.3	Delivery Charge	first 1,000,000	358,252	0.5299	1,898
6.4		over 1,000,000	243,630	0.3299	804
6	Total Distribution Charge		601,882		4,981
7.1	Gas Supply Load Balancing		601,882	0.2698	1,624
7.7	Gas Supply Transportation		601,882	4.8874	29,417
7.3	Curtailment Credit				(7,256)
8.1	Gas Supply Commodity - System		56,284	33.6032	18,913
8.2	Gas Supply Commodity - Buy/Sell		0	33.5855	0
8.	Total Gas Supply Charge		56,284		18,913
9.1	TOTAL DISTRIBUTION		601,882		4,981
9.2	TOTAL GAS SUPPLY LOAD BALANCINC		601,882		23,785
9.3	TOTAL GAS SUPPLY COMMODITY		56,284		18,913
9.	TOTAL RATE 170		601,882		47,678

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m^3	Col. 2 EB-2008-0219 Contracts & Volumes $10^3 m^3$	Col. 3 EB-2008-0219 Rate cents*	Col. 4 EB-2008-0219 Revenues $000
	RATE 200				
1.1	Customer Charge	Contracts	12	$0.00	0
1.2	Demand Charge		11,032	14.7000	1,622
1.3	Delivery Charge		151,354	1.1359	1,719
1.	Total Distribution Charge		151,354		3,341
2.1	Gas Supply Load Balancing		151,354	0.7175	1,086
2.2	Gas Supply Transportation		151,354	4.8874	7,397
2.3	Curtailment Credit				(95)
3.1	Gas Supply Commodity - System		118,849	33.6032	39,937
3.2	Gas Supply Commodity - Buy/Sell		0	33.5855	0
3.	Total Gas Supply Charge		118,849		39,937
4.1	TOTAL DISTRIBUTION		151,354		3,341
4.2	TOTAL GAS SUPPLY LOAD BALANCINC		151,354		8,388
4.3	TOTAL GAS SUPPLY COMMODITY		118,849		39,937
4.	TOTAL RATE 200		151,354		51,666

		Rate Block m^3	EB-2008-0219 Contracts & Volumes $10^3 m^3$	EB-2008-0219 Rate cents*	EB-2008-0219 Revenues $000
	RATE 300				
	Firm				
	Customer Charge		120	$500.00	60
	Demand Charge		1,077	24.7336	266
	Interruptible				
	Minimum Delivery Charge		51,702	0.3554	184
	Maximum Delivery Charge		0	0.9758	0
8.	TOTAL RATE 300 CDS		0		510

NOTE: * Cents unless otherwise noted.

1. Existing Rate 300 revenue is calculated using 2006 July QRAM Rate 305

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2008-0219 @ 37.69 MJ/m³ vs (B) EB-2008-0263 @ 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)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	192.00	168.00	24.00	14.3%	192.00	168.00	24.00	14.3%
1.3	DISTRIBUTION CHG.	$	237.49	257.92	(20.43)	-7.9%	358.02	388.79	(30.77)	-7.9%
1.4	LOAD BALANCING	§ $	177.66	182.17	(4.51)	-2.5%	271.99	278.88	(6.89)	-2.5%
1.5	SALES COMMDTY	$	1,035.02	1,034.25	0.77	0.1%	1,584.62	1,583.47	1.15	0.1%
1.6	TOTAL SALES	$	1,642.17	1,642.34	(0.17)	0.0%	2,406.63	2,419.14	(12.51)	-0.5%
1.7	TOTAL T-SERVICE	$	607.15	608.09	(0.94)	-0.2%	822.01	835.67	(13.66)	-1.6%
1.8	SALES UNIT RATE	$/m³	0.5360	0.5360	(0.0001)	0.0%	0.5130	0.5157	(0.0027)	-0.5%
1.9	T-SERVICE UNIT RATE	$/m³	0.1982	0.1985	(0.0003)	-0.2%	0.1752	0.1781	(0.0029)	-1.6%
1.10	SALES UNIT RATE	$/GJ	14.220	14.222	(0.0015)	0.0%	13.612	13.683	(0.0708)	-0.5%
1.11	T-SERVICE UNIT RATE	$/GJ	5.258	5.266	(0.0081)	-0.2%	4.649	4.727	(0.0773)	-1.6%

			Heating Only				Heating & Water Htg.			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	192.00	168.00	24.00	14.3%	192.00	168.00	24.00	14.3%
2.3	DISTRIBUTION CHG.	$	152.34	165.41	(13.07)	-7.9%	158.53	172.14	(13.61)	-7.9%
2.4	LOAD BALANCING	§ $	113.36	116.22	(2.86)	-2.5%	116.26	119.20	(2.94)	-2.5%
2.5	SALES COMMDTY	$	660.40	659.91	0.49	0.1%	677.30	676.78	0.52	0.1%
2.6	TOTAL SALES	$	1,118.10	1,109.54	8.56	0.8%	1,144.09	1,136.12	7.97	0.7%
2.7	TOTAL T-SERVICE	$	457.70	449.63	8.07	1.8%	466.79	459.34	7.45	1.6%
2.8	SALES UNIT RATE	$/m³	0.5719	0.5675	0.0044	0.8%	0.5706	0.5666	0.0040	0.7%
2.9	T-SERVICE UNIT RATE	$/m³	0.2341	0.2300	0.0041	1.8%	0.2328	0.2291	0.0037	1.6%
2.10	SALES UNIT RATE	$/GJ	15.174	15.058	0.1162	0.8%	15.140	15.034	0.1055	0.7%
2.11	T-SERVICE UNIT RATE	$/GJ	6.212	6.102	0.1095	1.8%	6.177	6.078	0.0986	1.6%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2008-0219 @ 37.69 MJ/m³ vs (B) EB-2008-0263 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				General & Water Htg.			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	192.00	168.00	24.00	14.3%	192.00	168.00	24.00	14.3%
3.3	DISTRIBUTION CHG.	$	385.04	418.12	(33.08)	-7.9%	89.50	97.21	(7.71)	-7.9%
3.4	LOAD BALANCING	§ $	292.68	300.13	(7.45)	-2.5%	62.68	64.27	(1.59)	-2.5%
3.5	SALES COMMDTY	$	1,705.23	1,703.95	1.28	0.1%	365.18	364.91	0.27	0.1%
3.6	TOTAL SALES	$	2,574.95	2,590.20	(15.25)	-0.6%	709.36	694.39	14.97	2.2%
3.7	TOTAL T-SERVICE	$	869.72	886.25	(16.53)	-1.9%	344.18	329.48	14.70	4.5%
3.8	SALES UNIT RATE	$/m³	0.5101	0.5131	(0.0030)	-0.6%	0.6562	0.6424	0.0138	2.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.1723	0.1756	(0.0033)	-1.9%	0.3184	0.3048	0.0136	4.5%
3.10	SALES UNIT RATE	$/GJ	13.534	13.614	(0.0802)	-0.6%	17.411	17.043	0.3674	2.2%
3.11	T-SERVICE UNIT RATE	$/GJ	4.571	4.658	(0.0869)	-1.9%	8.448	8.087	0.3608	4.5%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2008-0219 @ 37.69 MJ/m³ vs (B) EB-2008-0263 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				Com. Htg., Air Cond'ng & Other Uses			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	660.00	600.00	60.00	10.0%	660.00	600.00	60.00	10.0%
1.3	DISTRIBUTION CHG.	$	1,292.80	1,280.97	11.83	0.9%	1,658.73	1,643.55	15.18	0.9%
1.4	LOAD BALANCING §	$	1,302.26	1,347.58	(45.32)	-3.4%	1,686.62	1,745.34	(58.72)	-3.4%
1.5	SALES COMMDTY	$	7,662.98	7,658.49	4.49	0.1%	9,924.66	9,918.84	5.82	0.1%
1.6	TOTAL SALES	$	10,918.04	10,887.04	31.00	0.3%	13,930.01	13,907.73	22.28	0.2%
1.7	TOTAL T-SERVICE	$	3,255.06	3,228.55	26.51	0.8%	4,005.35	3,988.89	16.46	0.4%
1.8	SALES UNIT RATE	$/m³	0.4830	0.4816	0.0014	0.3%	0.4758	0.4750	0.0008	0.2%
1.9	T-SERVICE UNIT RATE	$/m³	0.1440	0.1428	0.0012	0.8%	0.1368	0.1362	0.0006	0.4%
1.10	SALES UNIT RATE	$/GJ	12.814	12.778	0.0364	0.3%	12.624	12.603	0.0202	0.2%
1.11	T-SERVICE UNIT RATE	$/GJ	3.820	3.789	0.0311	0.8%	3.630	3.615	0.0149	0.4%

			Medium Commercial Customer				Large Commercial Customer			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	660.00	600.00	60.00	10.0%	660.00	600.00	60.00	10.0%
2.3	DISTRIBUTION CHG.	$	6,962.04	6,897.93	64.11	0.9%	12,747.17	12,629.73	117.44	0.9%
2.4	LOAD BALANCING §	$	9,768.15	10,107.94	(339.79)	-3.4%	19,536.25	20,215.85	(679.60)	-3.4%
2.5	SALES COMMDTY	$	57,478.46	57,444.73	33.73	0.1%	114,956.58	114,889.11	67.47	0.1%
2.6	TOTAL SALES	$	74,868.65	75,050.60	(181.95)	-0.2%	147,900.00	148,334.69	(434.69)	-0.3%
2.7	TOTAL T-SERVICE	$	17,390.19	17,605.87	(215.68)	-1.2%	32,943.42	33,445.58	(502.16)	-1.5%
2.8	SALES UNIT RATE	$/m³	0.4415	0.4426	(0.0011)	-0.2%	0.4361	0.4374	(0.0013)	-0.3%
2.9	T-SERVICE UNIT RATE	$/m³	0.1026	0.1038	(0.0013)	-1.2%	0.0971	0.0986	(0.0015)	-1.5%
2.10	SALES UNIT RATE	$/GJ	11.715	11.743	(0.0285)	-0.2%	11.571	11.605	(0.0340)	-0.3%
2.11	T-SERVICE UNIT RATE	$/GJ	2.721	2.755	(0.0337)	-1.2%	2.577	2.617	(0.0393)	-1.5%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2008-0219 @ 37.69 MJ/m³ vs (B) EB-2008-0263 @ 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)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER	$	660.00	600.00	60.00	10.0%	660.00	600.00	60.00	10.0%
3.3	DISTRIBUTIO	$	2,291.98	2,270.94	21.04	0.9%	3,073.99	3,045.75	28.24	0.9%
3.4	LOAD BALAI	§ $	2,493.56	2,580.31	(86.75)	-3.4%	3,681.31	3,809.36	(128.05)	-3.4%
3.5	SALES COM	$	14,672.74	14,664.15	8.59	0.1%	21,661.84	21,649.13	12.71	0.1%
3.6	TOTAL SALE	$	20,118.28	20,115.40	2.88	0.0%	29,077.14	29,104.24	(27.10)	-0.1%
3.7	TOTAL T-SE	$	5,445.54	5,451.25	(5.71)	-0.1%	7,415.30	7,455.11	(39.81)	-0.5%
3.8	SALES UNIT	$/m³	0.4648	0.4647	0.0001	0.0%	0.4550	0.4554	(0.0004)	-0.1%
3.9	T-SERVICE I	$/m³	0.1258	0.1259	(0.0001)	-0.1%	0.1160	0.1167	(0.0006)	-0.5%
3.10	SALES UNIT	$/GJ	12.332	12.330	0.0018	0.0%	12.073	12.084	(0.0113)	-0.1%
3.11	T-SERVICE I	$/GJ	3.338	3.341	(0.0035)	-0.1%	3.079	3.095	(0.0165)	-0.5%

			Medium Industrial Customer				Large Industrial Customer			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER	$	660.00	600.00	60.00	10.0%	660.00	600.00	60.00	10.0%
4.3	DISTRIBUTIO	$	7,129.49	7,063.86	65.63	0.9%	12,871.60	12,753.00	118.60	0.9%
4.4	LOAD BALAI	§ $	9,768.14	10,107.94	(339.80)	-3.4%	19,536.21	20,215.78	(679.57)	-3.4%
4.5	SALES COM	$	57,478.44	57,444.73	33.71	0.1%	114,956.24	114,888.76	67.48	0.1%
4.6	TOTAL SALE	$	75,036.07	75,216.53	(180.46)	-0.2%	148,024.05	148,457.54	(433.49)	-0.3%
4.7	TOTAL T-SE	$	17,557.63	17,771.80	(214.17)	-1.2%	33,067.81	33,568.78	(500.97)	-1.5%
4.8	SALES UNIT	$/m³	0.4425	0.4436	(0.0011)	-0.2%	0.4365	0.4378	(0.0013)	-0.3%
4.9	T-SERVICE I	$/m³	0.1035	0.1048	(0.0013)	-1.2%	0.0975	0.0990	(0.0015)	-1.5%
4.10	SALES UNIT	$/GJ	11.741	11.769	(0.0282)	-0.2%	11.581	11.615	(0.0339)	-0.3%
4.11	T-SERVICE I	$/GJ	2.747	2.781	(0.0335)	-1.2%	2.587	2.626	(0.0392)	-1.5%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2008-0219 @ 37.69 MJ/m³ vs (B) EB-2008-0263 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				Rate 100 - Average Commercial Firm			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
1.2	CUSTOMER CHG.	$	1,454.76	1,427.64	27.12	1.9%	1,454.76	1,427.64	27.12	1.9%
1.3	DISTRIBUTION CHG.	$	17,726.21	17,427.50	298.71	1.7%	28,224.19	27,696.99	527.20	1.9%
1.4	LOAD BALANCING	$	18,791.75	19,227.80	(436.04)	-2.3%	33,161.94	33,931.47	(769.53)	-2.3%
1.5	SALES COMMDTY	$	114,429.16	114,361.99	67.17	0.1%	201,934.13	201,815.59	118.54	0.1%
1.6	TOTAL SALES	$	152,401.88	152,444.93	(43.04)	0.0%	264,775.02	264,871.69	(96.67)	0.0%
1.7	TOTAL T-SERVICE	$	37,972.72	38,082.94	(110.21)	-0.3%	62,840.89	63,056.10	(215.21)	-0.3%
1.8	SALES UNIT RATE	$/m³	0.4493	0.4494	(0.0001)	0.0%	0.4423	0.4425	(0.0002)	0.0%
1.9	T-SERVICE UNIT RATE	$/m³	0.1120	0.1123	(0.0003)	-0.3%	0.1050	0.1053	(0.0004)	-0.3%
1.10	SALES UNIT RATE	$/GJ	11.921	11.925	(0.0034)	0.0%	11.736	11.741	(0.0043)	0.0%
1.11	T-SERVICE UNIT RATE	$/GJ	2.970	2.979	(0.0086)	-0.3%	2.785	2.795	(0.0095)	-0.3%
			Rate 100 - Small Industrial Firm				Rate 100 - Average Industrial Firm			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
2.2	CUSTOMER CHG.	$	1,454.76	1,427.64	27.12	1.9%	1,454.76	1,427.64	27.12	1.9%
2.3	DISTRIBUTION CHG.	$	17,999.04	17,700.29	298.75	1.7%	28,465.63	27,938.42	527.21	1.9%
2.4	LOAD BALANCING	$	18,791.74	19,227.81	(436.07)	-2.3%	33,161.89	33,931.41	(769.52)	-2.3%
2.5	SALES COMMDTY	$	114,429.18	114,362.00	67.18	0.1%	201,933.77	201,815.26	118.51	0.1%
2.6	TOTAL SALES	$	152,674.72	152,717.74	(43.02)	0.0%	265,016.05	265,112.73	(96.68)	0.0%
2.7	TOTAL T-SERVICE	$	38,245.54	38,355.74	(110.20)	-0.3%	63,082.28	63,297.47	(215.19)	-0.3%
2.8	SALES UNIT RATE	$/m³	0.4501	0.4502	(0.0001)	0.0%	0.4428	0.4429	(0.0002)	0.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.1128	0.1131	(0.0003)	-0.3%	0.1054	0.1057	(0.0004)	-0.3%
2.10	SALES UNIT RATE	$/GJ	11.943	11.946	(0.0034)	0.0%	11.747	11.751	(0.0043)	0.0%
2.11	T-SERVICE UNIT RATE	$/GJ	2.992	3.000	(0.0086)	-0.3%	2.796	2.806	(0.0095)	-0.3%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2008-0219 @ 37.69 MJ/m³ vs (B) EB-2008-0263 @ 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.	$	1,470.36	1,457.64	12.72	0.9%	1,470.36	1,457.64	12.72	0.9%
3.3	DISTRIBUTION CHG.	$	10,062.75	9,995.13	67.62	0.7%	14,696.63	14,577.37	119.26	0.8%
3.4	LOAD BALANCING	$	16,433.96	16,505.36	(71.40)	-0.4%	29,001.56	29,127.56	(126.00)	-0.4%
3.5	SALES COMMDTY	$	114,603.16	114,334.85	268.31	0.2%	202,241.16	201,767.72	473.44	0.2%
3.6	TOTAL SALES	$	142,570.23	142,292.98	277.25	0.2%	247,409.71	246,930.29	479.42	0.2%
3.7	TOTAL T-SERVICE	$	27,967.07	27,958.13	8.94	0.0%	45,168.55	45,162.57	5.98	0.0%
3.8	SALES UNIT RATE	$/m³	0.4203	0.4195	0.0008	0.2%	0.4133	0.4125	0.0008	0.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.0825	0.0824	0.0000	0.0%	0.0755	0.0755	0.0000	0.0%
3.10	SALES UNIT RATE	$/GJ	11.152	11.131	0.0217	0.2%	10.967	10.945	0.0213	0.2%
3.11	T-SERVICE UNIT RATE	$/GJ	2.188	2.187	0.0007	0.0%	2.002	2.002	0.0003	0.0%

			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			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.	$	1,470.36	1,457.64	12.72	0.9%	1,470.36	1,457.64	12.72	0.9%
4.3	DISTRIBUTION CHG.	$	10,335.52	10,267.94	67.58	0.7%	14,938.08	14,818.82	119.26	0.8%
4.4	LOAD BALANCING	$	16,433.95	16,505.37	(71.42)	-0.4%	29,001.52	29,127.52	(126.00)	-0.4%
4.5	SALES COMMDTY	$	114,603.14	114,334.84	268.30	0.2%	202,240.83	201,767.36	473.47	0.2%
4.6	TOTAL SALES	$	142,842.97	142,565.79	277.18	0.2%	247,650.79	247,171.34	479.45	0.2%
4.7	TOTAL T-SERVICE	$	28,239.83	28,230.95	8.88	0.0%	45,409.96	45,403.98	5.98	0.0%
4.8	SALES UNIT RATE	$/m³	0.4211	0.4203	0.0008	0.2%	0.4137	0.4129	0.0008	0.2%
4.9	T-SERVICE UNIT RATE	$/m³	0.0833	0.0832	0.0000	0.0%	0.0759	0.0759	0.0000	0.0%
4.10	SALES UNIT RATE	$/GJ	11.174	11.152	0.0217	0.2%	10.977	10.956	0.0213	0.2%
4.11	T-SERVICE UNIT RATE	$/GJ	2.209	2.208	0.0007	0.0%	2.013	2.013	0.0003	0.0%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2008-0219 @ 37.69 MJ/m³ vs (B) EB-2008-0263 @ 37.69 MJ/m³

Item No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
		Rate 110 - Small Ind. Firm - 50% LF				Rate 110 - Average Ind. Firm - 50% LF			
		(A)	(B)	CHANGE		(A)	(B)	CHANGE	
				(A) - (B)	%			(A) - (B)	%
5.1 VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2 CUSTOMER CHG.	$	7,003.32	6,873.00	130.32	1.9%	7,003.32	6,873.00	130.32	1.9%
5.3 DISTRIBUTION CHG.	$	12,360.11	12,157.55	202.56	1.7%	202,226.10	198,850.21	3,375.89	1.7%
5.4 LOAD BALANCING	$	30,337.11	30,685.44	(348.33)	-1.1%	505,618.00	511,423.34	(5,805.34)	-1.1%
5.5 SALES COMMDTY	$	201,138.01	201,072.16	65.85	0.0%	3,352,295.89	3,351,198.53	1,097.36	0.0%
5.6 TOTAL SALES	$	250,838.55	250,788.15	50.40	0.0%	4,067,143.31	4,068,345.08	(1,201.77)	0.0%
5.7 TOTAL T-SERVICE	$	49,700.54	49,715.99	(15.45)	0.0%	714,847.42	717,146.55	(2,299.13)	-0.3%
5.8 SALES UNIT RATE	$/m³	0.4191	0.4190	0.0001	0.0%	0.4077	0.4078	(0.0001)	0.0%
5.9 T-SERVICE UNIT RATE	$/m³	0.0830	0.0831	(0.0000)	0.0%	0.0717	0.0719	(0.0002)	-0.3%
5.10 SALES UNIT RATE	$/GJ	11.119	11.116	0.0022	0.0%	10.817	10.820	(0.0032)	0.0%
5.11 T-SERVICE UNIT RATE	$/GJ	2.203	2.204	(0.0007)	0.0%	1.901	1.907	(0.0061)	-0.3%

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
		Rate 110 - Average Ind. Firm - 75% LF				Rate 115 - Large Ind. Firm - 80% LF			
		(A)	(B)	CHANGE		(A)	(B)	CHANGE	
				(A) - (B)	%			(A) - (B)	%
6.1 VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2 CUSTOMER CHG.	$	7,003.32	6,873.00	130.32	1.9%	7,436.04	7,309.92	126.12	1.7%
6.3 DISTRIBUTION CHG.	$	155,268.21	151,892.31	3,375.90	2.2%	845,876.50	831,751.17	14,125.33	1.7%
6.4 LOAD BALANCING	$	505,617.95	511,423.27	(5,805.32)	-1.1%	3,445,209.08	3,479,264.44	(34,055.36)	-1.0%
6.5 SALES COMMDTY	$	3,352,295.56	3,351,198.19	1,097.37	0.0%	23,466,072.26	23,458,390.64	7,681.62	0.0%
6.6 TOTAL SALES	$	4,020,185.04	4,021,386.77	(1,201.73)	0.0%	27,764,593.88	27,776,716.17	(12,122.29)	0.0%
6.7 TOTAL T-SERVICE	$	667,889.48	670,188.58	(2,299.10)	-0.3%	4,298,521.62	4,318,325.53	(19,803.91)	-0.5%
6.8 SALES UNIT RATE	$/m³	0.4030	0.4031	(0.0001)	0.0%	0.3976	0.3978	(0.0002)	0.0%
6.9 T-SERVICE UNIT RATE	$/m³	0.0669	0.0672	(0.0002)	-0.3%	0.0616	0.0618	(0.0003)	-0.5%
6.10 SALES UNIT RATE	$/GJ	10.692	10.695	(0.0032)	0.0%	10.549	10.553	(0.0046)	0.0%
6.11 T-SERVICE UNIT RATE	$/GJ	1.776	1.782	(0.0061)	-0.3%	1.633	1.641	(0.0075)	-0.5%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2008-0219 @ 37.69 MJ/m³ vs (B) EB-2008-0263 @ 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)	CHANGE	
					(A) - (B)	%			(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.	$	1,374.48	1,354.08	20.40	1.5%	3,325.08	3,270.36	54.72	1.7%
7.3	DISTRIBUTION CHG.	$	8,023.7	7,888.45	135.20	1.7%	77,922.2	76,548.17	1,374.02	1.8%
7.4	LOAD BALANCING	$	24,209.13	24,394.45	(185.32)	-0.8%	394,230.76	397,757.42	(3,526.66)	-0.9%
7.5	SALES COMMDTY	$	201,751.19	201,600.36	150.83	0.1%	3,352,295.89	3,351,198.53	1,097.36	0.0%
7.6	TOTAL SALES	$	235,358.45	235,237.34	121.11	0.1%	3,827,773.92	3,828,774.48	(1,000.56)	0.0%
7.7	TOTAL T-SERVICE	$	33,607.26	33,636.98	(29.72)	-0.1%	475,478.03	477,575.95	(2,097.92)	-0.4%
7.8	SALES UNIT RATE	$/m³	0.3932	0.3930	0.0002	0.1%	0.3837	0.3838	(0.0001)	0.0%
7.9	T-SERVICE UNIT RATE	$/m³	0.0561	0.0562	(0.0000)	-0.1%	0.0477	0.0479	(0.0002)	-0.4%
7.10	SALES UNIT RATE	$/GJ	10.433	10.427	0.0054	0.1%	10.180	10.183	(0.0027)	0.0%
7.11	T-SERVICE UNIT RATE	$/GJ	1.490	1.491	(0.0013)	-0.1%	1.265	1.270	(0.0056)	-0.4%

			Rate 170 - Average Ind. Interr. - 75% LF				Rate 170 - Large Ind. Interr. - 75% LF			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(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.	$	3,325.08	3,270.36	54.72	1.7%	3,325.08	3,270.36	54.72	1.7%
8.3	DISTRIBUTION CHG.	$	70,737.4	69,363.37	1,374.02	2.0%	379,593.3	369,975.15	9,618.11	2.6%
8.4	LOAD BALANCING	$	394,230.73	397,757.42	(3,526.69)	-0.9%	2,759,615.50	2,784,302.25	(24,686.75)	-0.9%
8.5	SALES COMMDTY	$	3,352,295.56	3,351,198.19	1,097.37	0.0%	23,466,072.26	23,458,390.64	7,681.62	0.0%
8.6	TOTAL SALES	$	3,820,588.76	3,821,589.34	(1,000.58)	0.0%	26,608,606.10	26,615,938.40	(7,332.30)	0.0%
8.7	TOTAL T-SERVICE	$	468,293.20	470,391.15	(2,097.95)	-0.4%	3,142,533.84	3,157,547.76	(15,013.92)	-0.5%
8.8	SALES UNIT RATE	$/m³	0.3830	0.3831	(0.0001)	0.0%	0.3810	0.3811	(0.0001)	0.0%
8.9	T-SERVICE UNIT RATE	$/m³	0.0469	0.0472	(0.0002)	-0.4%	0.0450	0.0452	(0.0002)	-0.5%
8.10	SALES UNIT RATE	$/GJ	10.161	10.164	(0.0027)	0.0%	10.110	10.112	(0.0028)	0.0%
8.11	T-SERVICE UNIT RATE	$/GJ	1.245	1.251	(0.0056)	-0.4%	1.194	1.200	(0.0057)	-0.5%

Measure of 2009 Revenues vs 2009 Revenue Requirement
December 31, 2009
(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	3,368.00	1,937.06	1,183.59	1.21	0.00	73.09	34.60	6.59	4.41	24.24	47.68	51.67	0.51	1.80	1.56
2.	Unbilled Revenues	(3.26)	1.79	(4.32)	0.00	0.00	(0.13)	(0.20)	0.00	0.00	(0.21)	(0.19)	0.00	0.00	0.00	0.00
3.	Total Revenues	3,364.74	1,938.85	1,179.27	1.21	0.00	72.96	34.39	6.59	4.42	24.03	47.49	51.67	0.51	1.80	1.56
4.	Proposed 2009 Revenue Requirement	3,364.74	1,931.46	1,183.22	1.87	(0.00)	73.25	35.58	6.50	4.36	24.91	48.46	51.28	0.50	1.79	1.56
5.	Measure of Revenues vs Revenue Requirement	1.00	1.00	1.00	0.65	0.00	1.00	0.97	1.01	1.01	0.96	0.98	1.01	1.01	1.01	1.00

Measure of 2009 Revenues vs 2009 Revenue Requirement
Excluding Gas Supply Commodity
December 31, 2009
(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	1,679.04	958.59	566.93	0.48	0.00	49.06	33.10	6.59	3.30	16.63	28.77	11.73	0.51	1.80	1.56
2.	Unbilled Revenues	(3.26)	1.79	(4.32)	0.00	0.00	(0.13)	(0.20)	0.00	0.00	(0.21)	(0.19)	0.00	0.00	0.00	0.00
3.	Total Revenues	1,675.78	960.38	562.61	0.48	0.00	48.93	32.90	6.59	3.30	16.42	28.57	11.73	0.51	1.80	1.56
4.	Proposed 2009 Revenue Requirement	1,675.78	952.99	566.55	1.14	(0.00)	49.22	34.09	6.50	3.24	17.31	29.55	11.35	0.50	1.79	1.56
5.	Measure of Revenues vs Revenue Requirement excluding Gas Supply Commodity	1.00	1.01	0.99	0.42	0.00	0.99	0.97	1.01	1.02	0.95	0.97	1.03	1.01	1.01	1.00

Total 2009 Revenue Requirement
December 31, 2009
(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE	Reference
1	PRODUCT COSTS	1,689.0	978.5	616.7	0.7	-	24.0	1.5	-	1.1	7.6	18.9	39.9	-	-	-	Ex.B/T3/S10/P4/L1 & Ex.B/T3/S10/P5/L1
2	PIPELINE TRANS. AND LOAD BALANCING	632.8	266.8	258.0	0.1	0.0	35.0	26.5	-	2.8	11.4	23.8	8.4	-	-	-	Ex.B/T3/S10/P4/L2 & Ex.B/T3/S10/P5/L2
3	STORAGE	149.8	75.0	68.7	0.0	0.0	1.7	0.4	-	(0.5)	1.2	1.7	1.7	-	-	-	Ex.B/T3/S10/P4/L3 & Ex.B/T3/S10/P5/L3
4	DISTRIBUTION	446.8	264.1	154.1	0.0	0.0	8.7	6.2	6.2	0.2	2.5	3.2	1.3	0.2	0.2	-	Ex.B/T3/S10/P4/L4 & Ex.B/T3/S10/P5/L4
5	CUSTOMER RELATED	444.6	347.2	85.6	1.0	(0.0)	3.8	1.1	0.3	0.7	2.3	0.9	0.0	0.1	0.0	1.56	Ex.B/T3/S10/P5/L5
Total 2009 Revenue Requirement		3,363.0	1,931.5	1,183.2	1.9	(0.0)	73.3	35.6	6.5	4.4	24.9	48.5	51.3	0.3	0.2	1.56	

2009 Gas Cost to Operations Revenue Requirement
December 31, 2009
(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE	Allocation
	SUPPLY COSTS																
	PRODUCT COSTS																
1.1	Annual Commodity	1,675.8	971.8	610.3	0.7	-	24.0	1.5	-	1.1	7.6	18.9	39.9	-	-	-	1.1
1	Total Gas Cost	1,675.8	971.8	610.3	0.7	-	24.0	1.5	-	1.1	7.6	18.9	39.9	-	-	-	
	PIPELINE TRANS. AND LOAD BALANCING																
2.1	Peak	11.2	5.8	5.2	0.0	0.0	0.1	0.0	-	-	-	-	0.1	-	-	-	3.1
2.2	Seasonal	23.6	11.3	10.7	-	-	0.4	0.1	-	-	0.4	0.5	0.3	-	-	-	3.2
2.3	Annual - Transportation	558.6	226.5	220.5	0.1	-	34.0	26.4	-	2.9	11.1	29.6	7.5	-	-	-	1.2
2.4	Seasonal Credit	(8.2)	-	-	-	-	-	-	-	-	(0.8)	(7.3)	(0.1)	-	-	-	
2	Total Pipeline Trans. Cost	585.3	243.7	236.3	0.1	0.0	34.5	26.5	-	2.9	10.7	22.9	7.8	-	-	-	
	STORAGE																
3.1	Deliverability	54.4	28.2	25.2	0.0	0.0	0.4	0.1	-	-	-	-	0.5	-	-	-	3.1
3.2	Space	62.4	30.0	28.2	-	-	1.0	0.2	-	-	1.0	1.3	0.8	-	-	-	3.2
3.3	Seasonal Credit	(0.5)	-	-	-	-	-	-	-	(0.5)	-	-	-	-	-	-	
3	Total Storage	116.3	58.2	53.4	0.0	0.0	1.4	0.3	-	(0.5)	1.0	1.3	1.3	-	-	-	
	DISTRIBUTION																
4.1	Commodity	11.8	4.8	4.7	0.0	-	0.7	0.6	-	0.1	0.2	0.6	0.2	-	-	-	1.3
4	Total Distribution	11.8	4.8	4.7	0.0	-	0.7	0.6	-	0.1	0.2	0.6	0.2	-	-	-	
Total 2009 Gas Cost to Operations Revenue Requirement		2,389.2	1,278.4	904.7	0.9	0.0	60.5	28.8	-	3.5	19.4	43.7	49.1	-	-	-	

2009 Distribution Revenue Requirement
December 31, 2009
(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	SUPPLY RELATED															
1	PRODUCT RELATED	13.2	6.7	6.3	0.0	-	0.0	0.0	-	0.0	0.1	0.0	0.1	-	-	-
2	LOAD BALANCING RELATED	47.6	23.1	21.7	(0.0)	0.0	0.6	(0.0)	-	(0.0)	0.7	0.9	0.6	-	-	-
	FACILITIES' COSTS															
3	STORAGE	33.5	16.8	15.4	0.0	0.0	0.4	0.1	-	-	0.2	0.3	0.4	-	-	-
4	DISTRIBUTION	434.9	259.3	149.5	0.0	0.0	7.9	5.6	6.2	0.1	2.3	2.6	1.1	0.2	0.2	-
5	CUSTOMER RELATED	444.6	347.2	85.6	1.0	(0.0)	3.8	1.1	0.3	0.7	2.3	0.9	0.0	0.1	0.0	1.56
Total Distribution Revenue Requirement		973.8	653.0	278.5	1.0	(0.0)	12.7	6.7	6.5	0.8	5.5	4.7	2.2	0.3	0.2	1.56

2009 Y Factor Revenue Requirement
December 31, 2009
(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300 Firm	Col. 14 RATE 300 Int	Col. 15 Assignment
	Y Factor: Other															
1.1	2009 Gas in Storage and Working Cash Carrying Cost	50.4	24.20	22.75	-	-	0.78	0.15	-	-	0.77	1.09	0.66	-	-	3.2
1.2	DSM 2009 Board Approved Amount	24.3	11.38	9.01	-	-	0.66	1.23	-	0.06	0.51	1.42	-	-	-	Direct
1.3	CIS/ Customer Care 2009	94.1	86.24	7.84	0.00	-	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	4.5
		168.8	121.81	39.59	0.00	-	1.46	1.38	0.00	0.06	1.29	2.51	0.66	0.00	0.00	
	Y Factor: Capital Investment															
1.4	2009 Leave to Construct	3.2	1.47	1.35	0.00	0.00	0.08	0.05	0.19	0.00	0.02	0.01	0.03	0.00	-	2.1
		3.2	1.47	1.35	0.00	0.00	0.08	0.05	0.19	0.00	0.02	0.01	0.03	0.00	-	
Total Y-Factor Revenue requirement		172.0	123.28	40.94	0.00	0.00	1.54	1.43	0.19	0.06	1.30	2.51	0.70	0.00	0.00	

2009 Distribution Revenue Requirement minus Y Factors
December 31, 2009

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300 Firm	Col. 14 RATE 300 Int	Col. 15 DIRECT PURCHASE
	Total Distribution Revenue Requirement	973.8	653.0	278.5	1.0	(0.0)	12.7	6.7	6.5	0.8	5.5	4.7	2.2	0.3	0.2	1.6
	Y Factor: Other															
1.1	2009 Gas in Storage and Working Cash Carrying Cost	50.4	24.2	22.7	-	-	0.8	0.2	-	-	0.8	1.1	0.7	-	-	
1.2	DSM 2009 Board Approved Amount	24.3	11.4	9.0	-	-	0.7	1.2	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2009	94.1	86.2	7.8	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2009 Leave to Construct	3.2	1.5	1.4	0.0	0.0	0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.0	-	
	Total Y-Factor Revenue requirement	172.0	123.3	40.9	0.0	0.0	1.5	1.4	0.2	0.1	1.3	2.5	0.7	0.0	0.0	0.0
	Total DRR minus Y Factor	801.8	529.7	237.5	1.0	(0.0)	11.2	5.3	6.3	0.7	4.2	2.2	1.5	0.3	0.2	1.6

Allocators
December 31, 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. 16
	FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 F	RATE 300 Int	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	4,994.8	2,896.6	1,819.2	2.2	0.0	71.5	4.4	0.0	3.3	22.5	56.3	118.8	0.0	0.0	0.0
1.2 Bundled Annual Deliveries	11,348.1	4,601.6	4,479.0	2.6	0.0	691.0	536.5	0.0	58.1	226.1	601.9	151.4	0.0	0.0	0.0
1.3 Total Annual Deliveries	11,399.8	4,601.6	4,479.0	2.6	0.0	691.0	536.5	0.0	58.1	226.1	601.9	151.4	0.0	51.7	0.0
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	105,632.1	48,458.3	44,726.0	7.3	0.0	2,547.8	1,618.1	6,222.1	7.3	560.2	272.8	1,120.6	91.7	0.0	0.0
2.2 Delivery Demand HP	98,434.2	48,458.3	44,726.0	7.3	0.0	2,547.8	1,618.1	0.0	7.3	560.2	272.8	0.0	91.7	144.8	0.0
2.3 Delivery Demand LP	98,127.6	48,458.3	44,726.0	7.3	0.0	2,547.8	1,311.5	0.0	7.3	560.2	272.8	0.0	91.7	144.8	0.0
2.4 Cust. Rel Plant	1,906,437	1,747,095	158,767	28	0	249	48	3	38	167	31	1	9	1	0.0
STORAGE RESPONSIBILITY															
3.1 Deliverability	52.4	27.2	24.3	0.0	0.0	0.4	0.1	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0
3.2 Space	2,728.6	1,310.1	1,231.5	0.0	0.0	42.5	8.2	0.0	0.0	41.5	59.0	35.8	0.0	0.0	0.0
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1,906,437	1,747,095	158,767	28	0	249	48	3	38	167	31	1	8	1	0.0

Allocation Percentages
December 31, 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
	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	0.5799	0.3642	0.0004	0.0000	0.0143	0.0009	0.0000	0.0007	0.0045	0.0113	0.0238	0.0000	0.0000	0.0000
1.2 Bundled Annual Deliveries	1.0000	0.4055	0.3947	0.0002	0.0000	0.0609	0.0473	0.0000	0.0051	0.0199	0.0530	0.0133	0.0000	0.0000	0.0000
1.3 Total Annual Deliveries	1.0000	0.4037	0.3929	0.0002	0.0000	0.0606	0.0471	0.0000	0.0051	0.0198	0.0528	0.0133	0.0000	0.0045	0.0000
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	1.0000	0.4587	0.4234	0.0001	0.0000	0.0241	0.0153	0.0589	0.0001	0.0053	0.0026	0.0106	0.0009	0.0000	0.0000
2.2 Delivery Demand HP	1.0000	0.4923	0.4544	0.0001	0.0000	0.0259	0.0164	0.0000	0.0001	0.0057	0.0028	0.0000	0.0009	0.0015	0.0000
2.3 Delivery Demand LP	1.0000	0.4938	0.4558	0.0001	0.0000	0.0260	0.0134	0.0000	0.0001	0.0057	0.0028	0.0000	0.0009	0.0015	0.0000
2.4 Cust. Rel Plant	1.0000	0.9164	0.0833	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	0.5185	0.4636	0.0000	0.0000	0.0071	0.0018	0.0000	0.0000	0.0000	0.0000	0.0089	0.0000	0.0000	0.0000
3.2 Space	1.0000	0.4801	0.4513	0.0000	0.0000	0.0156	0.0030	0.0000	0.0000	0.0152	0.0216	0.0131	0.0000	0.0000	0.0000
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1.0000	0.9164	0.0833	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000

RATE 1 – RATE CHANGE – EXPLANATORY COMMENTS

Not Required

RATE 6 - RATE CHANGE – EXPLANATORY COMMENTS

Not Required

LARGE VOLUME RATES – RATE INCREASE - EXPLANATORY COMMENTS

Not Required

Witnesses: J. Collier
A. Kacicnik

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 2009 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 to be acquired directly at the Dawn.

   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 2009 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	1 961.8	69.3
Ontario Production	1.5	0.0
Peaking	15.5	0.5
Chicago Supply	2 276.3	80.4
Delivered Supply	983.9	34.7
	5 239.0	184.9

Commodity Costs

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

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

6. The Company prepared its gas supply forecast based upon a 21-day average of various indices from July 18, 2008 to August 15, 2008 for the 12 months commencing January 1, 2009 and applied these monthly prices to the 2009 budgeted annual volume gas purchases.

7. In an effort to remove the impact of commodity costs changes the Company removed the impact of the updated price forecast and the October 1, 2008 QRAM prices in a fashion similar to the 2008 forecast of gas supply cost that was filed in EB-2007-0615.

8. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2009 PGVA. Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2009 PGVA. While the Company does not anticipate acquiring gas in 2009 via means other than the traditional transportation paths (i.e., TCPL, Alliance/Vector) the possibility exists, perhaps not this year but in the future, to acquire gas via alternative means (i.e., LNG, Shale Gas, Rockies)

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 98 810 10^3m^3 (3.5 Bcf) during the winter season of the test year.

Transportation

10. Enbridge has a number of Firm Transportation ("FT") and other service entitlements in place for system gas sourced in Western Canada or in the United States (at the Chicago hub as well as U.S. supply area), or both, during the Test Year. These include service entitlements with TransCanada, Alliance Pipeline and Vector Pipeline. For purposes of this forecast contracts were priced based upon current

tolls and contracts that had an expiry date during the Test Year were deemed to be renewed.

11. The Company also has M12 service entitlements with Union Gas totaling 2,225,102 GJ/d (2,081 MMcf/d) for delivery of gas by Union at Dawn for storage injection or onward transportation, for gas withdrawn from storage at Tecumseh or Union, or both, and for gas sourced in Western Canada or the United States, or both, and delivered at Dawn for onward transportation. The Company also has M16 transportation capacity with Union to facilitate the Chatham ”D” Storage project. The gas cost forecast assumed January 1, 2008 Union tolls.

Storage

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

13. Enbridge also held a storage entitlement with Union Gas Limited for 21,259,700 GJ broken down into three contracts with varied expiry dates. In its decision in the NGEIR proceeding dated November 7, 2006 the Board ruled that these contracts should be priced at cost of service rates, with a phased in approach to market based storage prices. The Board ruled that as these contracts expired that they then would be replaced with market based storage.

14. Following that directive the Company issued a Request For Proposal (“RFP”) for market based storage services to replace the first of the three contracts that expired March 31, 2008. Following the RFP process the Company settled on three separate storage contracts that came into effect April 1, 2008. This year the

Company issued a second RFP for market based storage to replace the second of the three contracts that will expire March 31, 2009. The Company is currently finalizing the details with three different parties for services to become effective April 1, 2009. The cost consequences of these storage contracts have been included in the forecast for 2009 gas costs.

Energy Content

15. Enbridge has used a gross heating value of 37.69 MJ/m^3 to convert quantities (i.e., GJ, Dth) into volumes (i.e., 10^3m^3, MMcf). Quantities are the units specified in many of Enbridge's gas purchase and transportation service agreements, whereas Enbridge rates are volumetric.

Schedules Exhibit B, Tab 5, Schedule 1

16. The gas cost schedules (pages 1 & 2) provide the summary of the forecasted gas cost to operations for 2009 based upon an updated supply and transportation portfolio to meet the forecasted volumetric requirement for 2009. Page 3 provides a breakdown of the forecasted 2009 storage and transportation costs that are shown at Item #12, Column 2 of page 2. Page 4 provides a breakdown of the monthly gas in storage balances for rate base and QRAM purposes in 2009. Pages 5 through 8 are the comparable schedules for 2008 assuming the October 1, 2008 QRAM Reference Price.

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

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	628,064.3	204,786.7	326.060	8.651
1.3	Western - @ Nova - TCPL	358,056.6	114,682.5	320.292	8.498
1.4	Western Buy/Sell - with Fuel	4,117.4	1,379.3	334.984	8.888
1.5	Western - @ Alliance	971,582.8	350,174.3	360.416	9.563
1.6	Less TCPL Fuel Requirement	(39,254.4)	0.0		
1.	Total Western Canadian Supplies	1,922,566.5	671,022.7	349.024	9.260
	Short Term Supplies				
2.	Peaking/Seasonal	15,480.0	14,015.2	905.372	24.022
3.	Ontario Production	1,460.1	538.5	368.816	9.786
	Chicago Supplies				
4.1	Vector 1st Tranche	11,975.5	4,203.6	351.017	9.313
4.2	Vector 2nd Tranche	809,492.2	291,182.4	359.710	9.544
4.3	Vector 3rd Tranche	1,454,852.4	523,325.0	359.710	9.544
4.	Total Chicago Supplies	2,276,320.1	818,711.0	359.664	9.543
	Delivered Supplies				
5.1	Link Supplies	-	-	0.000	0.000
5.2	Ontario Delivered	983,880.1	388,551.8	394.918	10.478
5.	Total Other Delivered Supplies	983,880.1	388,551.8	394.918	10.478
6.	Total Supply Costs	5,199,706.8	1,892,839.1	364.028	9.658
	Transportation Costs				
7.1	TCPL - FT - Demand		45,604.7		
7.2	- FT - Commodity	950,983.8	4,422.6	4.651	0.123
7.3	Capacity Discounts		0.0		
7.4	- STS - CDA		3,914.9		
7.5	- STS - EDA		2,775.5		
7.6	- Dawn to CDA Exchange		9,414.5		
7.7	- Dawn to EDA Exchange		14,684.2		
7.8	Other Charges		0.0		
7.9	Nova Transmission		1,966.4		
7.10	ANR/Michcon Transportation		0.0		
7.11	Link Pipeline		0.0		
7.12	Alliance Pipeline		40,267.4		
7.13	Vector Pipeline - 1st Tranche		8,163.2		
7.14	Vector Pipeline - 2nd Tranche		6,718.5		
7.15	Vector Pipeline - 3rd Tranche		12,074.7		
7.	Total Transportation Costs		150,006.6		
8.	Total Before PGVA Adjustment	5,199,706.8	2,042,845.8	392.877	10.424
9.	PGVA Adjustment		(42,166.4)		
10.	Total Purchases & Receipt	5,199,706.8	2,000,679.4	384.768	10.209

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

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	5,199,706.8	2,000,679.4	384.768	10.209
11.	Storage Fluctuation	(149,825.6)	(57,648.0)		
12.	Commodity Cost to Operations	5,049,881.3	1,943,031.4	384.768	
13.	Storage and Transportation Costs		110,811.7		
14.	Gas Cost to Operations	5,049,881.3	2,053,843.0	406.711	10.791
15.	Ontario T-Service Credits		115,749.5		
16.	Western T-Service		220,059.3		
17.	Forecasted Gas Costs	5,049,881.3	2,389,651.9	473.210	12.555
	Regulatory Adjustments				
18.	NGV Vehicles		0.0		
19.	LRAM Adjustment		0.0		
20.	Accounting Adjustments		0.0		
21.	Forecasted Utility Gas Costs	5,049,881.3	2,389,651.9	473.210	12.555

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
YEAR ENDED DECEMBER 31, 2009

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

SUMMARY OF STORAGE & TRANSPORTATION COSTS
FISCAL 2009

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2009	Col. 2 Fiscal 2009 Storage Charges Recovered in Fiscal 2009	Col. 3 Fiscal 2008 Storage Charges Recovered in Fiscal 2009	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2009
	Storage				
1.1	Chatham D	136.9	73.4	61.5	134.9
1.2	Space	811.2	434.8	809.7	1,244.5
1.3	Peak	1,005.6	539.0	868.3	1,407.2
1.4	Injection	96.1	28.1	79.6	107.7
1.5	Withdrawal	120.3	120.3	0.0	120.3
1.6	Market Based Storage	15,819.0	8,478.8	3,734.6	12,213.4
1.7	Other	588.3	588.3	(1,357.8)	(769.5)
1.	Total Storage	18,577.5	10,262.7	4,195.8	14,458.6
	Transportation				
2.	Total Transportation	65,424.7	35,066.8	29,374.2	64,441.0
	Dehydration				
3.1	Demand	982.8	526.8	444.4	971.2
3.2	Commodity	195.2	195.2	0.0	195.2
3.	Total Dehydration	1,178.0	722.0	444.4	1,166.4
4.	Total Union Gas	85,180.2	46,051.5	34,014.4	80,066.0
	Fuel Costs				
5.1	Tecumseh	6,303.2	3,919.6	1,384.8	5,304.5
5.2	Union Storage	1,905.2	1,306.7	555.0	1,861.8
5.3	Union Transportation	23,913.9	22,681.8	897.7	23,579.5
5.	Total Fuel Costs	32,122.3	27,908.1	2,837.6	30,745.7
6.	Total Storage & Transportation	117,302.5	73,959.7	36,852.0	110,811.7
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				110,811.7

2009
GAS IN STORAGE
MONTH END BALANCES AND
AVERAGE OF MONTHLY AVERAGES

Item #		10^3m^3	Value ($000)
Month end balances except @ January 1			
1.	January 1	1,445,857.8	662,979.6
2.	January	1,048,580.1	464,950.7
3.	February	738,171.9	309,913.8
4.	March	498,943.7	194,443.1
5.	April	478,709.2	192,091.5
6.	May	594,764.0	253,496.3
7.	June	781,245.5	346,799.9
8.	July	1,118,763.1	499,735.5
9.	August	1,474,823.3	659,883.3
10.	September	1,789,988.9	802,188.5
11.	October	1,969,226.7	881,923.2
12.	November	1,910,620.2	850,956.2
13.	December	1,595,683.5	693,898.0
14.		1,160,383.9	511,235.1

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2008

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	426,592.4	136,013.4	318.837	8.459
1.3	Western - @ Nova - TCPL	358,056.6	112,576.3	314.409	8.342
1.4	Western Buy/Sell - with Fuel	4,515.5	1,484.9	328.838	8.725
1.5	Western - @ Alliance	966,103.9	341,841.1	353.835	9.388
1.6	Less TCPL Fuel Requirement	(34,428.0)	0.0		
1.	Total Western Canadian Supplies	1,720,840.5	591,915.7	343.969	9.126
	Short Term Supplies				
2.	Peaking/Seasonal	56,300.0	30,002.3	532.901	14.139
3.	Ontario Production	1,464.1	531.4	362.926	9.629
	Chicago Supplies				
4.1	Vector 1st Tranche	8,303.0	2,866.6	345.251	9.160
4.2	Vector 2nd Tranche	807,280.4	286,209.5	354.535	9.407
4.3	Vector 3rd Tranche	1,450,877.4	514,387.5	354.535	9.407
4.	Total Chicago Supplies	2,266,460.8	803,463.6	354.501	9.406
	Delivered Supplies				
5.1	Link Supplies	76,840.8	28,473.3	370.550	9.832
5.2	Ontario Delivered	902,349.7	349,377.0	387.186	10.273
5.	Total Other Delivered Supplies	979,190.4	377,850.4	385.880	10.238
6.	Total Supply Costs	5,024,255.8	1,803,763.3	359.011	9.525
	Transportation Costs				
7.1	TCPL - FT - Demand		36,049.2		
7.2	- FT - Commodity	754,736.5	3,510.0	4.651	0.123
7.3	Capacity Discounts		0.0		
7.4	- STS - CDA		4,417.4		
7.5	- STS - EDA		2,775.5		
7.6	- Dawn to CDA Exchange		9,414.5		
7.7	- Dawn to EDA Exchange		14,684.2		
7.8	Union C1 Transportation		0.0		
7.9	Nova Transmission		1,966.4		
7.10	ANR/Michcon Transportation		979.5		
7.11	Link Pipeline		119.8		
7.12	Alliance Pipeline		40,268.1		
7.13	Vector Pipeline - 1st Tranche		8,163.5		
7.14	Vector Pipeline - 2nd Tranche		6,718.7		
7.15	Vector Pipeline - 3rd Tranche		12,075.2		
7.	Total Transportation Costs		141,142.0		
8.	Total Before PGVA Adjustment	5,024,255.8	1,944,905.3	387.103	10.271
9.	PGVA Adjustment		0.0		
10.	Total Purchases & Receipt	5,024,255.8	1,944,905.3	387.103	10.271

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2008

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	5,024,255.8	1,944,905.3	387.103	10.271
11.	Storage Fluctuation	(189,879.8)	(73,503.1)		
12.	Commodity Cost to Operations	4,834,376.1	1,871,402.2	387.103	
13.	Storage and Transportation Costs		97,546.6		
14.	Gas Cost to Operations	4,834,376.1	1,968,948.8	407.281	10.806
15.	Ontario T-Service Credits		137,312.9		
16.	Western T-Service		224,256.6		
17.	Forecasted Gas Costs	4,834,376.1	2,330,518.3	482.072	12.790
	Regulatory Adjustments				
18.	NGV Vehicles		0.0		
19.	LRAM Adjustment		0.0		
20.	Accounting Adjustments		0.0		
21.	Forecasted Utility Gas Costs	4,834,376.1	2,330,518.3	482.072	12.790

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
YEAR ENDED DECEMBER 31, 2008

Item #		
1.	Sendout To Operations	4,834,376.1
2.	T-Service Volumes	6,835,325.0
3.	Total Sendout	11,669,701.0
4.1	Residential Sales	2,782,953.6
4.2	Commercial Sales	1,582,996.2
4.3	Industrial Sales	292,196.7
4.4	T-Service	6,802,993.2
4.5	Rate 200 T-Service (Gazifere)	33,476.2
4.6	Rate 200 Sales (Gazifere)	116,517.3
4.7	Company Use	6,284.9
4.8	Unaccounted For (UAF)	39,444.4
4.9	Unbilled Forecast - Sales	(9,780.5)
4.10	Unbilled Forecast - T-Service	(1,144.5)
4.11	Lost and Unaccounted For (LUF)	23,763.5
4.12	LUF Capitalized	0.0
4.	Total System Requirements	11,669,701.0

SUMMARY OF STORAGE & TRANSPORTATION COSTS
FISCAL 2008

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2008	Col. 2 Fiscal 2008 Storage Charges Recovered in Fiscal 2008	Col. 3 Fiscal 2007 Storage Charges Recovered in Fiscal 2008	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2008
	Storage				
1.1	Chatham D	136.9	79.2	62.3	141.5
1.2	Space	1,651.2	1,060.1	1,205.7	2,265.7
1.3	Peak	4,162.5	1,335.7	1,519.1	2,854.8
1.4	Injection	113.9	35.6	69.8	105.4
1.5	Withdrawal	95.3	95.3	0.0	95.3
1.6	Market Based Storage	8,309.7	3,462.5	0.0	3,462.5
1.7	Other	(1,260.2)	(696.6)	(2,051.6)	(2,748.2)
1.	Total Storage	13,209.3	5,371.8	805.3	6,177.1
	Transportation				
2.	Total Transportation	61,940.1	34,842.2	29,272.3	64,114.5
	Dehydration				
3.1	Demand	907.2	510.3	379.3	889.6
3.2	Commodity	127.4	127.4	0.0	127.4
3.	Total Dehydration	1,034.6	637.7	379.3	1,017.0
4.	Total Union Gas	76,184.0	40,851.7	30,456.9	71,308.6
	Fuel Costs				
5.1	Tecumseh	5,467.2	3,549.8	2,243.4	5,793.1
5.2	Union Storage	1,795.1	1,123.2	706.5	1,829.8
5.3	Union Transportation	18,266.5	17,334.6	1,280.5	18,615.1
5.	Total Fuel Costs	25,528.8	22,007.6	4,230.4	26,238.0
6.	Total Storage & Transportation	101,712.8	62,859.3	34,687.3	97,546.6
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				97,546.6

2008
GAS IN STORAGE
MONTH END BALANCES AND
AVERAGE OF MONTHLY AVERAGES

Item #		10^3m^3
Month end balances except @ January 1		
1.	January 1	1,451,650.7
2.	January	1,072,257.6
3.	February	732,256.7
4.	March	523,019.7
5.	April	500,234.2
6.	May	644,127.2
7.	June	838,178.4
8.	July	1,190,065.5
9.	August	1,551,988.8
10.	September	1,874,817.0
11.	October	2,047,321.6
12.	November	1,965,230.9
13.	December	1,641,530.5
14.		1,207,174.0

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

Line No.	Account Description	Account Acronym	Col. 1 Actual at August 31, 2008 Principal ($000's)	Col. 2 Actual at August 31, 2008 Interest ($000's)	Col. 3 Forecast at December 31, 2008 Principal ($000's)	Col. 4 Forecast at December 31, 2008 Interest ($000's)	
	Non Commodity Related Accounts						
1.	Demand Side Management V/A	2008 DSMVA	(2,372.8)	(15.1)	-	-	
2.	Demand Side Management V/A	2007 DSMVA	(616.1)	(112.6)	(616.1)	(119.4)	
3.	Lost Revenue Adjustment Mechanism	2008 LRAM	-	-	-	-	
4.	Lost Revenue Adjustment Mechanism	2007 LRAM	-	-	(301.3)	-	
5.	Shared Savings Mechanism V/A	2008 SSMVA	-	-	-	-	
6.	Shared Savings Mechanism V/A	2007 SSMVA	-	-	8,248.0	-	
7.	Class Action Suit D/A	2008 CASDA	18,838.2	1,092.4	18,838.2	1,302.8	a)
8.	Deferred Rebate Account	2008 DRA	2,045.0	2.7	2,045.0	25.5	
9.	Gas Distribution Access Rule Costs D/A	2008 GDARCDA	646.7	9.8	788.2	17.6	
10.	Ontario Hearing Costs V/A	2008 OHCVA	1,514.7	14.6	1,714.7	32.4	
11.	Manufactured Gas Plant D/A	2008 MGPDA	178.8	6.2	430.3	9.3	
12.	Electric Program Earnings Sharing D/A	2008 EPESDA	-	-	-	-	
13.	Unbundled Rate Implementation Cost D/A	2008 URICDA	-	-	-	-	
14.	Unbundled Rates Customer Migration V/A	2008 URCMVA	-	-	485.7	-	
15.	Open Bill Service D/A	2008 OBSDA	437.1	9.0	-	-	
16.	Open Bill Access V/A	2008 OBAVA	-	-	-	-	
17.	Carbon Dioxide Offset Credits D/A	2008 CDOCDA	-	-	-	-	
18.	Municipal Permit Fees D/A	2008 MPFDA	-	-	800.0	6.6	
19.	Average Use True-Up V/A	2008 AUTUVA	-	-	-	-	
20.	Tax Rate and Rule Change V/A	2008 TRRCVA	-	-	-	-	b)
21.	Earnings Sharing Mechanism D/A	2008 ESMDA	-	-	-	-	
22.	Total non commodity related accounts		20,671.6	1,007.0	32,432.7	1,274.8	
	Commodity Related Accounts						
23.	Purchased Gas V/A	2008 PGVA	7,658.3	(525.6)	59,688.7	(254.9)	c)
24.	Transactional Services D/A	2008 TSDA	-	-	(2,635.0)	-	
25.	Unaccounted for Gas V/A	2008 UAFVA	-	-	-	-	
26.	Storage and Transportation D/A	2008 S&TDA	(3,105.5)	(76.9)	(2,093.2)	(107.3)	
27.	Total commodity related accounts		4,552.8	(602.5)	54,960.5	(362.2)	
28.	Total Deferral and Variance Accounts		25,224.4	404.5	87,393.2	912.6	

a) This is the forecast CASDA balance at the end of 2008. The Board has approved the future clearance of approximately one quarter of this amount over each of the years 2009, 2010, 2011 & 2012.

b) As indicated in Exhibit B-1-2, page 3, an entry to this account may be required in 2008 with clearance at July 2009, if anticipated CCA rate changes which have not occurred to date, do not occur by year end. This treatment was approved by the Board within the 2008 EB-2007-0615 Settlement Agreement.

c) This is the projected December 31, 2008 balance upon which the Rider "C" clearance and unit rates are designed and therefore does not include the impacts of the projected clearance.

NOTE: Page 2 shows the current estimated balances which would be cleared on a one time basis at July 1, 2009. Estimated balances could change. Additionally, just as approved in past years, a one time true up of PGVA year end related variances will be analyzed and cleared across the appropriate types of service and customer classes at July 1, 2009.

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNTS
CURRENT ESTIMATED DECEMBER 31, 2008 BALANCES FOR CLEARANCE JULY 1, 2009

Line No.	Account Description	Account Acronym	Col. 1 Current est. balance for clearance July 1, 2009 Principal ($000's)	Col. 2 Current est. balance for clearance July 1, 2009 Interest ($000's)	
	Non Commodity Related Accounts				
1.	Demand Side Management V/A	2008 DSMVA	-	-	
2.	Demand Side Management V/A	2007 DSMVA	(616.1)	(119.4)	
3.	Lost Revenue Adjustment Mechanism	2008 LRAM	-	-	
4.	Lost Revenue Adjustment Mechanism	2007 LRAM	(301.3)	-	
5.	Shared Savings Mechanism V/A	2008 SSMVA	-	-	
6.	Shared Savings Mechanism V/A	2007 SSMVA	8,248.0	-	
7.	Class Action Suit D/A	2008 CASDA	4,709.6	325.7	a)
8.	Deferred Rebate Account	2008 DRA	2,045.0	25.5	
9.	Gas Distribution Access Rule Costs D/A	2008 GDARCDA	788.2	17.6	
10.	Ontario Hearing Costs V/A	2008 OHCVA	1,714.7	32.4	
11.	Manufactured Gas Plant D/A	2008 MGPDA	430.3	9.3	
12.	Electric Program Earnings Sharing D/A	2008 EPESDA	-	-	
13.	Unbundled Rate Implementation Cost D/A	2008 URICDA	-	-	
14.	Unbundled Rates Customer Migration V/A	2008 URCMVA	485.7	-	
15.	Open Bill Service D/A	2008 OBSDA	-	-	
16.	Open Bill Access V/A	2008 OBAVA	-	-	
17.	Carbon Dioxide Offset Credits D/A	2008 CDOCDA	-	-	
18.	Municipal Permit Fees D/A	2008 MPFDA	800.0	6.6	
19.	Average Use True-Up V/A	2008 AUTUVA	-	-	
20.	Tax Rate and Rule Change V/A	2008 TRRCVA	-	-	b)
21.	Earnings Sharing Mechanism D/A	2008 ESMDA	-	-	
22.	Total non commodity related accounts		18,304.1	297.7	
	Commodity Related Accounts				
23.	Purchased Gas V/A	2008 PGVA	-	-	c)
24.	Transactional Services D/A	2008 TSDA	(2,635.0)	-	
25.	Unaccounted for Gas V/A	2008 UAFVA	-	-	
26.	Storage and Transportation D/A	2008 S&TDA	(2,093.2)	(107.3)	
27.	Total commodity related accounts		(4,728.2)	(107.3)	
28.	Total Deferral and Variance Accounts		13,575.9	190.4	

a) This is the portion of the ending 2008 CASDA balance which was approved by the Board to be cleared in 2009.

b) As indicated in Exhibit B-1-2, page 3, an entry to this account may be required in 2008 with clearance at July 2009, if anticipated CCA rate changes which have not occurred to date, do not occur by year end. This treatment was approved by the Board within the 2008 EB-2007-0615 Settlement Agreement.

c) The PGVA balance, as indicated and approved in the EB-2008-0263 QRAM proceeding, is an estimate which is projected to be cleared through rate rider "C" by March 31, 2009.

NOTE: The current estimated balances which would be cleared on a one time basis at July 1, 2009 could change. Additionally, just as approved in past years, a one time true up of PGVA year end related variances will be analyzed and cleared across the appropriate types of service and customer classes at July 1, 2009.