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October 17, 2011

VIA RESS, EMAIL and COURIER

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

Dear Ms Walli:

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

In addition to the evidence filed on September 30, 2011 for the above noted proceeding, enclosed please find the following updated exhibits:

- Exhibit B, Tab 1, Schedule 2;
- Exhibit B, Tab 2, Schedule 2;
- Exhibit B, Tab 2, Schedule 5, and Appendices;
- Exhibit B, Tab 3, Schedule 1 to Schedule 10; and
- Exhibit C, Tab 1, Schedule 2.

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

Two paper copies being forwarded to the Board via courier.

Please contact the undersigned if you have any questions.

Yours truly,

Lesley Austin

Lesley Austin
Regulatory Coordinator, Regulatory Affairs

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

2012 REVENUE PER CUSTOMER CAP, DISTRIBUTION AND
TOTAL REVENUE DETERMINATION

Row		Col. 1 2012	
1.	2011 Total Approved Revenue ($millions)	2,404.9	
2.	Gas Costs to operations (at Oct. 1, 2010 ref. price)	1,416.3	
3.	2011 Approved Distribution Revenue	988.6	
4.	2011 Gas in storage related carrying costs (at Oct. 1, 2010 ref. price)	(30.9)	
5.	DSM 2011 amount	(26.7)	
6.	CIS / Cust. Care 2011 amount	(97.4)	
7.	Power generation projects 2011 amount	(3.5)	
8.	Distribution Revenue Sub-total	830.1	
9.	Ratepayer 50% share of 2012 incremental tax amounts	(4.6)	
10.	Distribution Revenue base (subject to the escalation formula, $millions)	825.5	
11.	Average Number of Customers (Beginning)	1,965,537	
12.	Distribution Revenue per Customer 2012 (Beginning)	$ 419.99	
13.	GDP IPI FDD	1.72%	
14.	Inflation Coefficient (allowed % of GDP IPI FDD)	45.00%	
15.	Escalation Factor, 100 plus (GDP IPI FDD multiplied by the inflation coeff.)	100.77%	
16.	Distribution Revenue per Customer 2012 (Ending)	$ 423.23	
17.	Average Number of Customers (Ending)	1,984,734	
18.	Distribution Revenue (resulting from the escalation formula, $millions)	839.99	
	Y-Factors		
19.	2012 Gas in storage related carrying costs (at October 1, 2011 ref. price)	30.60	
20.	2012 DSM Y-factor amount	28.10	/u
21.	CIS / Customer Care 2012 approved amount	99.20	
22.	Power generation projects 2012 amount	6.60	
23.	Total 2012 Y-Factors	164.50	/u
	Z-Factors		
24.	2012 Pension funding requirement	16.60	/u
25.	2012 Crossbore / Sewer Lateral program requirement	3.80	
26.	Total 2012 Z-Factors	20.40	/u
27.	Total 2012 Distribution Revenues	1,024.89	/u
28.	2012 Gas Costs to operations (at October 1, 2011 ref. price)	1,515.50	
29.	2012 Total Revenue ($millions)	2,540.39	/u

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

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

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

Process

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

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

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

Witnesses: K. Culbert
A. Kacicnik
D. Small

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

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

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

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

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

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

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

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

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

Witnesses: K. Culbert
A. Kacicnik
D. Small

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

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

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

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

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

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

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

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

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

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

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

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

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

22. Row 20 increases the $839.99 million distribution revenue by $28.1 million, which is the Company's proposed 2012 DSM operating cost budget in accordance with the EB-2008-0346 guidelines dated June 30, 2011, and as will be included in evidence in the Company's 2012 DSM Plan proceeding, EB-2011-0295. The addition of 2012 DSM costs, to 2012 total revenue, is required as 2011 DSM costs were previously removed as explained in the narrative for Row 5. /u

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

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

25. Row 23, $164.5 million, is the sum of Rows 19 through 22, total 2012 Y factors. /u

26. Row 24, $16.6 million, represents the Company's forecast 2012 pension funding requirement being requested to be established as a Z factor within the context of the IR model settlement agreement approved in EB-2007-0615. Evidence supporting the recovery and treatment of this item and amount is shown at Exhibit B, Tab 2, Schedule 5, and Exhibit C, Tab 1, Schedule 2. /u

Witnesses: K. Culbert
A. Kacicnik
D. Small

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

28. Row 26, $20.4 million, is the sum of rows 24 and 25, total 2012 Z factors. /u

29. Row 27, $1,024.89 million, is Enbridge's total 2012 distribution revenue before gas costs which 2012 rates will be designed to recover. /u

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

31. Row 29, $2,540.39 million, is the 2012 total revenue arrived at and to be used to design rates, following the application of the sum of all of the elements of the agreed upon incentive escalation formula. The 2012 rates will be designed to recover this entire amount based on the forecast of 2012 volumes associated with the formula. /u

Witnesses: K. Culbert
A. Kacicnik
D. Small

Y FACTOR – DSM PROGRAM

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

2. The DSM Y factor amount included in the 2012 IR distribution revenue formula is $28.1 million, as allowed within the EB-2008-0346 guideline and to be requested in /u
   the EB-2011-0295 Natural Gas DSM Plan proceeding. The amount is shown at Exhibit B, Tab 1, Schedule 2, page 1, Column 1, Row 20.

Witness: K. Culbert

2012 PENSION FUNDING REQUIREMENT

Background

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

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

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

Witnesses: S. Kancharla
R. Lei
A. Patel

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

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

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

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

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

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

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

Recent Events and their Impact

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

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

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

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

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

<u>Purpose of this Evidence</u>

12. This evidence has been prepared and filed due to the likelihood that EGD will be required to make annual contributions to the RPP and SERP starting in 2012. Based on Mercer's estimate for the December 31, 2011 valuation, EGD would need to contribute $16.0 million to the RPP and $0.6 million to the SERP for a total /u
contribution of $16.6 million which represents the annual current employee service /u
costs[3].

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

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

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

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

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

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

iv. Any cost increase must be prudently incurred; and

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

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

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

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

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

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

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

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

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

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

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

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

Witnesses: S. Kancharla
R. Lei
A. Patel

iv. Any cost increase must be prudently incurred:

22. EGD's estimated 2012 contribution requirement of $16.6 million arises from the changes to the PBAO and primarily includes employee service cost related contributions. The estimated contribution amount is based Mercer's best estimate as of August 31, 2011 and must be made to remain compliant with the PBAO, thereby satisfying the prudence criteria. The strong past performance of the plan, which led to the accumulation of a significant funding surplus prior to the downturn in financial markets (as noted in Appendix A) further establishes the Company's prudence in management of the plan. /u

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

23. The anticipated cost increase for 2012 is expected to be $16.6 million, significantly higher than the threshold of $1.5 million. /u

Proposed mechanics of the requested cost recovery

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

25. EGD proposes that the estimated pension cost of $16.6 million be included in the revenue requirement as a Z factor item in this application. Further, given the timing and the potential variability associated with the year-end valuation and the /u

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

26. Once the valuation at December 31, 2011 becomes available and the contribution requirement in 2012 (i.e. pension cost) becomes known, any variance from the estimated cost of $16.6 million will be transferred to this variance account for future /u refund to or collection from ratepayers. This process will ensure that the net recovery in rates is fully aligned with the costs ultimately incurred by EGD.

<u>Summary</u>

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

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

29. In light of the above, the Company respectfully requests Board approval for inclusion of $16.6 million in pension costs as a Z factor in its revenue requirement /u for 2012. In addition, the Company requests that the Board approve the establishment of a pension cost variance account.

Witnesses: S. Kancharla
R. Lei
A. Patel

EGD – REGISTERED PENSION PLAN ("RPP")

($ millions)

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

Solvency Basis[4]									
Assets	711.7	735.6	698.1	635.2	801.7	820.6	766.7	705.7	/u
Liabilities	789.4	702.0	666.1	611.7	664.8	640.9	631	562	
Funding Excess/(Deficiency)	(77.7)	33.6	32.0	23.5	136.9	179.7	135.7	143.7	/u

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

MERCER CONSULTING. OUTSOURCING. INVESTMENTS.

ESTIMATED 2012 FUNDING COSTS
EGD PENSION PLANS
03 OCTOBER 2011

MARSH & McLENNAN COMPANIES

Note to reader regarding actuarial valuations and projections:

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

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

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

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

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

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

CONTENTS

1

Introduction

Purpose

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

Note that information contained in this report reflects all assets, liabilities and costs in respect of all employers participating in the EGD RPP, except where specifically noted.

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

2

Background Information

Determination of Contribution Requirements

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

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

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

Regulatory Changes

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

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

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

Historical Funding

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

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

Current Economic Environment

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

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

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

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

Implications for the EGD RPP

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

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Financial Results

Estimated Financial Position at December 31, 2011

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

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

Projected Going-Concern Balance Sheet at December 31, 2011

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

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

Projected Solvency Balance Sheet at December 31, 2011

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

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

Summary of Minimum Required Contributions – EGD RPP

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

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

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

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

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

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

Enbridge Gas Distribution Inc.'s Share of Funding

In addition to Enbridge Gas Distribution Inc., two other smaller employers participate in the EGD RPP. The following tables provide the same results as those on page 6, but are only in respect of Enbridge Gas Distribution Inc.'s share of costs.

Estimated Cash Contributions – Valuation Not Filed ($Millions) – *EGDI ONLY*	**2012**
DB current service cost (projected)	$14.7
Special payments (projected)	n/a
Total DB contributions (projected)	$14.7
DC current service cost (projected)	$1.3
Total DB and DC contributions (projected)	**$16.0**

Estimated Cash Contributions – Valuation Filed ($Millions) – *EGDI ONLY*	**2012**
DB current service cost (projected)	$16.0
Special payments (projected)	$16.9
Total DB contributions (projected)	$32.9
DC current service cost (projected)	$1.3
Total DB and DC contributions (projected)	**$34.2**

Summary of Minimum Required Contributions – SERP/SSERP

Enbridge also sponsors two supplementary pension arrangements:

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

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

Enbridge Gas Distribution Inc. is the only employer participating in the SERP and SSERP.

Important to Note

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

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

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

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

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

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Actuarial Opinion

In our opinion, for the purposes of the projection,

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

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

Chris Heller	Allen Hornung
FCIA, FSA	FCIA, FSA
October 3, 2011	October 3, 2011
Date	Date

APPENDIX A

Required Disclosures

Terms of Engagement

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

- They have been prepared in accordance with applicable pension legislation and based on methods and actuarial assumptions that are consistent with actuarial standards of practice in Canada;
- We have reflected a margin for adverse deviations in our going concern projection by reducing the going-concern discount rate by 0.59% per year; and
- We have reflected the Company's decisions for determining the solvency funding requirements, summarized as follows:
  - The same plan wind-up scenario was hypothesized for both hypothetical wind-up and solvency valuations;
  - Certain excludable benefits were excluded from the solvency liabilities; and
  - The solvency financial position was determined on a projected market value basis.
- We have projected assets forward using benchmark asset returns (net of expenses) to August 31, 2011 and our best estimate of asset returns (net of expenses) for the remainder of 2011. Projected cash flows over 2011 have also been incorporated.
- We have projected liabilities forward using the expected cost of benefits accruing over 2011, reflecting interest over 2011 and adjusting year-end assumptions based on the economic environment as at August 31, 2011. Projected cash flows over 2011 have also been incorporated.

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

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

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

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

Subsequent Events

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

Next Required Valuation

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

Gain and Loss Analysis

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

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

Solvency Incremental Cost

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

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

Discount Rate Sensitivity

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

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

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

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

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

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

APPENDIX B

Plan Assets

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

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

Investment Policy

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

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

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

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

APPENDIX C

Actuarial Methods and Assumptions

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

Valuation of Assets

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

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

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

Valuation of Actuarial Liabilities and Current Service Cost

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

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

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

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

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

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

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

Sample rates from the age related tables are summarized below:

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

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

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

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

Discount Rate

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

The discount rate is comprised of the following:

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

The discount rate was developed as follows:

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

Inflation

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

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

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

Pensionable Earnings

This assumption is based on Company expectations.

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

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

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

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

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

Thereby giving rise to the following benefits:

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

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

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

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

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

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

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

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

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

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

Termination Expenses

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

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

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

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

Incremental Cost

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

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

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

APPENDIX D

Membership Data

Analysis of Membership Data at December 31, 2010

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

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

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

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

APPENDIX E

Summary of EGD RPP Provisions

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

DB Component

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

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

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

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

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

DC Component

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

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

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

MERCER

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2012 PROPOSED RATES

1. This evidence outlines the Company's proposal with respect to 2012 rates within its Revenue Cap per Customer Incentive Regulation Model approved in EB-2007-0615 (Test Year 2008). The evidence lays out the development of the proposed 2012 rates including the proposed recovery of the 2012 revenue requirement.

2. The Company is seeking Board approval of each of the following:
   a. recovery of the 2012 revenue requirement from all elements of the Company's rates;
   b. the proposed rates for each customer class; and
   c. the Rate Handbook filed under Exhibit B, Tab 3, Schedule 2.

3. The Rate Handbook filed under Exhibit B, Tab 3, Schedule 2 reflects proposed changes to Rate 200 (Wholesale Service) with respect to the provisions for interruptible service. Except for the proposed changes to Rate 200, all other components of the Rate Handbook filed under this exhibit remain as approved in EB-2011-0296 (October 1, 2011 QRAM).

Components of the 2012 Revenues

4. The derivation of the Company's 2012 revenues reflecting the Revenue Cap per Customer incentive regulation model is presented at Exhibit B, Tab 1, Schedule 2, page 1. Row 29 of that exhibit represents total proposed revenues for 2012 in the amount of $2,540.39 million. /u

Witnesses: J. Collier
A. Kacicnik
M. Suarez

5. As shown at rows 27, 28, and 29, the 2012 proposed revenues consist of:

2012 Distribution Revenues	$1,024.89	/u
2012 Gas Cost to Operations	$1,515.50	
2012 Total Revenues	$2,540.39	/u

6. The 2012 distribution revenues are comprised of: a) 2012 base distribution revenue in the amount of $839.99 million (Row 18), which is determined using the Revenue Cap per Customer incentive regulation escalation formula, b) distribution related Y factor revenues in the amount of $164.50 million (Row 23) and c) distribution related Z factor revenues in the amount of $20.40 million (Row 26). /u /u

7. The 2012 Gas Cost to Operations reflects pass-through of gas supply costs such as commodity, upstream transportation, contracted storage, and load balancing. The Gas Cost to Operations evidence is filed at Exhibit B, Tab 4, Schedule 1.

2012 Rate Impacts

8. The Company has designed rates to recover the proposed 2012 revenues of $2,540.39 million. Table 1 below provides a summary of the resulting average rate impacts by rate class. Rate impacts for customers taking service under bundled rates are expressed on a T-service basis. Rate impacts for customers taking service under unbundled rates are expressed on a delivery rate basis. /u

9. The proposed rate impacts are relative to the existing October 1, 2011 QRAM Board approved rates filed under EB-2011-0296 and reflect the proposed 2012 revenue requirement, the proposed 2012 volumetric forecast, and the proposed 2012 Gas Cost to Operations budget.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

Table 1: 2012 Proposed Average Rate Impacts

Rate Class	T-Service Rate Impact /u
1	2.1%
6	0.9%
9	0.6%
100	-1.4%
110	-0.9%
115	-1.7%
135	-0.6%
145	-2.4%
170	-2.0%
200	-0.2%
	Delivery Rate Impact /u
125	1.2%
300	1.2%

10. The 2012 rate impacts are lower for all rate classes than the threshold levels requiring supplementary explanation as outlined in the EB-2007-0615 Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, page 31.

<u>Rate Design Exhibits</u>

11. Rate design exhibits are filed at Exhibit B, Tab 3, Schedules 3 to 9. The exhibits present the proposed recovery of the 2012 revenues. The schedules are organized in the following manner:

    a) Schedule 3 of Exhibit B, Tab 3 summarizes, by rate class, and rate component, the revenues at proposed rates which are forecast to be recovered in 2012. Schedule 4 displays the revenues by rate class and component and by unit rate in conjunction with the associated volumes.
    b) Schedule 5 summarizes the revenues shown in Schedule 3 and presents the unbilled revenues at proposed rates.
    c) Schedule 6 compares the current unit rates from EB-2011-0269 (October 1, 2011 QRAM) to the proposed unit rates.

Witnesses: J. Collier
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d) Schedule 7, pages 1 and 2 show the derivation of gas supply, gas supply load balancing, and transportation rates. Page 3 depicts the generation of the seasonal and interruptible credits.
e) Schedule 8 shows the detailed revenue calculations by rate class.
f) Annual bill comparisons indicating the impact of the Company's proposed rates on typical rate class customers relative to the EB-2011-0269 (October 1, 2011 QRAM) rates are shown at Schedule 9.

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

<u>Rate Design: Gas Supply Revenues</u>

13. The gas supply revenues reflect the 2012 forecast of Gas Costs to Operations (at October 1, 2011 QRAM reference price) in the amount of $1,515.50 million including changes to the Company's 2012 gas supply portfolio relative to the 2011 gas supply portfolio as well as storage and storage associated transportation costs. Changes to these elements are not captured through the Company's QRAM rate changes. The 2012 gas supply portfolio includes the changes to transportation capacity for System Reliability. The cost consequences of these changes are not reflected in the 2012 rate adjustment but will take effect in the Company's January 1, 2012 QRAM rates. This is consistent with the Company's QRAM methodology which adjusts rates in each quarter of a fiscal year to reflect changes in commodity and upstream transportation costs.

14. The Company's existing October 1, 2011 QRAM rates have a Purchased Gas Variance Account ("PGVA") reference price of $196.778 10^3m^3. The PGVA reference price is comprised of commodity, transportation and load balancing costs. Applying the individual price elements underpinning this reference price to the

forecast gas supply mix for 2012 yields a PGVA reference price of \$194.573 10^3m^3, which represents a decrease from the October 2011 QRAM level.

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

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

Rate Design: Distribution Revenues

17. The distribution revenues include a base 2012 distribution revenue requirement of \$839.99 million, which is derived using the proposed Revenue Cap per Customer incentive regulation escalation formula, distribution revenue requirement of \$164.50 million for the Y factors and Z factor distribution revenue requirement of /u
\$20.40 million. /u

Witnesses: J. Collier
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18. The distribution revenue requirement is recovered in the Company's rates primarily from the delivery charges, however, some distribution-related costs are recovered from the commodity and load balancing charges.

19. The Company used allocators reflecting 2012 forecast to assign the test year distribution revenue requirement to the customer classes. By updating forecasts and allocators annually, the assignment of revenue requirement by rate class, and consequently rate impacts, remain responsive to factors such as customer growth, volumes gain or loss and customer migration between various rates and service offerings. The Y factor and Z factor revenue requirements were assigned to the customer classes based on specific drivers for that type of expenditure such as peak demand or customer numbers.

Rate Design: 2012 Proposed Rates

20. In the rate design process, consistent with the approach to design of rates in a cost of service environment, the Company used the assignment of the 2012 revenue requirement (Exhibit B, Tab 3, Schedule 10, pp. 1 - 9) as a guide to establish the proposed rates.

21. The Company has designed the proposed 2012 rates while balancing the following objectives: rate stability, continuity, rate class characteristics, and rate impacts for the various customer classes, market acceptance, avoidance of rate shock, and continuance of competitive position.

22. The Company also validated that there is an appropriate assignment of revenue responsibility among rate classes and that rates remain related to revenue requirement by measuring the proposed revenues to be recovered from each rate

class relative to the assignment of the test year revenue requirement. This validation is provided at Exhibit B, Tab 3, Schedule 10, pages 1 and 2.

Other

System Gas and DPAC Charges

23. Consistent with the 2011 Settlement Agreement (EB-2010-0146, Exhibit N1, Tab 1, Schedule, 1 p. 11) regarding the Direct Purchase Administration Charge ("DPAC") and the System Gas Administration Fee, the Company has retained the 2012 DPAC and System Gas fees at the 2010 level. For DPAC, the monthly fixed charge remains at $75 per pool, and the monthly account charge of $0.21 per account continues to apply. For the System Gas Fee, the unit rate of 0.0224 ¢/m^3 remains unchanged at the 2010 level.

Low-Income DSM

24. In its Demand Side Management Guidelines for Natural Gas Utilities issued on June 30, 2011, the Board provided a framework for natural gas utilities' multi-year DSM plans from 2012 – 2014. Section 8.3 of the Guidelines directed the utilities to recover funding for Low-Income DSM programs "from all rate classes, to be consistent with the electricity conservation and demand management framework, as well as the Low-Income Energy Assistance Program ("LEAP") Emergency Financial Assistance program" (p. 26) based on the Distribution Revenue Requirement ("DRR") per rate class.

25. The Company has allocated its 2012 Low-Income DSM costs to all rate classes in proportion to its 2011 DRR. Given the timing and consultative requirements of the DSM proceeding for the 2012 program year (EB-2011-0295), it was necessary to determine and provide an allocation of the Low Income budget prior to the

Witnesses: J. Collier
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completion of the assignment of the 2012 DRR. Allocations of the 2012 DRR and the 2011 DRR are very similar. The Low-Income DSM budget allocation is provided at Exhibit B, Tab 3, Schedule 10, page 6 at Line 1.3.

<u>Proposed Z Factors</u>

26. As outlined at Exhibit B, Tab 1, Schedule 2, page 1, the Company is proposing new Z factors for 2012: (1) Pension funding requirement (Row 24), and (2) Cross bore/ Sewer Lateral program requirement (Row 25).

27. The Company proposes to allocate the Pension funding requirement proportionally to the allocation of the 2012 distribution revenue requirement (excluding proposed Z factors) for each rate class. The revenue requirement for the Cross bore/Sewer Lateral program is allocated on the services allocation factor. The allocations of the proposed Z Factor amounts to each rate class are found at Exhibit B, Tab 3, Schedule 10, page 6, at Lines 1.7 and 1.8.

<u>Rate Handbook</u>

28. Rate 200 is a wholesale service available to distributors outside EGD's franchise area who use EGD's distribution system to supply gas to their customers. The Company is proposing to change its Rate 200 (Wholesale Service) rate schedule, specifically, the provisions of interruptible service under Rate 200. The objective of the proposed changes is to make the wording uniform with EGD's interruptible service under Rate 145 and Rate 170 that was addressed in the OEB's System Reliability Decision (EB-2010-0231). The proposed changes are highlighted with bold and italic font in the Rate 200 rate schedule found under Exhibit B, Tab 3, Schedule 2, page 32.

Witnesses: J. Collier
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RATE HANDBOOK

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

INDEX

Part I

GLOSSARY OF TERMS

In this Handbook of Rates and Distribution Services, each term set out below shall have the meaning set out opposite it:

Annual Turnover Volume ("ATV"): The sum of the contracted volumes injected into and withdrawn from storage by an applicant within a contract year.

Annual Volume Deficiency: The difference between the Minimum Annual Volume and the volume actually taken in a contract year, if such volume is less than the Minimum Annual Volume.

Applicant: The party who makes application to the Company for one or more of the services of the Company and such term includes any party receiving one or more of the services of the Company.

Authorized Volume: In regards to Sales Service Agreements, the Contract Demand.

In regards to Bundled Transportation Service arrangements, the Contract Demand (CD) less the amount by which the Applicant's Mean Daily Volume (MDV) exceeds the Daily Delivered Volume (Delivery) and less the volume by which the Applicant has been ordered to curtail or discontinue the use of gas (Curtailment Volume) or otherwise represented as:

CD – (MDV – Delivery) – Curtailment Volume

Back-stopping: A service whereby alternative supplies of gas may be available in the event that an Applicant's supply of gas is not available for delivery to the Company.

Banked Gas Account: A record of the amount of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of volume of gas taken by the Applicant at the Terminal Location (debits)

Billing Contract Demand: Applicable only to new customers who take Dedicated Service under Rate 125. The Company and the Applicant shall determine a Billing Contract Demand which would result in annual revenues over the term of the contract that would enable the Company to recover the invested capital, return on capital, and O&M costs of the Dedicated Service in accordance with its system expansion policies.

Billing Month: A period of approximately thirty (30) days following which the Company renders a bill to an applicant. The billing month is determined by the Company's monthly Reading and Billing Schedule. With respect to rate 135 LVDC's, there are eight summer months and four winter months.

Board: Ontario Energy Board. (OEB)

Bundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Company utilizing Load balancing resources.

Buy/Sell Arrangement: An arrangement, the terms of which are provided for in one or more agreements to which one or more of an end user of gas (being a party that buys from the Company gas delivered to a Terminal Location), an affiliate of an end user and a marketer, broker or agent of an end user is a party and the Company is a party, and pursuant to which the Company agrees to buy from the end user or its affiliate a supply of gas and to sell to the end user gas delivered to a Terminal Location served from the gas distribution network. The Company will not enter into any new buy/sell agreement after April 1, 1999.

Buy/Sell Price: The Price per cubic meter which the Company would pay for gas purchased pursuant to a Buy/Sell Arrangement in which the purchase takes place in Ontario.

Commodity Charge: A charge per unit volume of gas actually taken by the Applicant, as distinguished from a demand charge which is based on the maximum daily volume an Applicant has the right to take.

Company: Enbridge Gas Distribution Inc.

Contract Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule for each Terminal Location which is the maximum volume of gas the Company is required to deliver on a daily basis under a Large Volume Distribution Contract.

Cubic Metre ("m^3"): That volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa") occupies one cubic metre. "10^3m^3" means 1,000 cubic metres.

Curtailment: An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

Curtailment Credit: A credit available to interruptible customers to recognize the benefits they provide to the system during the winter months.

Curtailment Delivered Supply (CDS): An additional volume of gas, in excess of the Applicant's Mean Daily Volume and determined by mutual agreement between the Applicant and the Company, which is Nominated and delivered by or on behalf of the Applicant to a point of interconnection with the Company's distribution system on a day of Curtailment.

Customer Charge: A monthly fixed charge that reflects being connected to the gas distribution system.

Daily Consumption VS Gas Quantity: The volume of natural gas taken on a day at a Terminal Location as measured by daily metering equipment or, where the Company does not own and maintain daily metering equipment at a Terminal Location, the volume of gas taken within a billing period divided by the number of days in the billing period.

Daily Delivered Volume: The volume of gas accepted by the Company as having been delivered by an Applicant to the Company on a day.

Dedicated Service: An Unbundled Service provided through a gas distribution pipeline that is initially constructed to serve a single customer, and for which the volume of gas is measured through a billing meter that is directly connected to a third party transporter or other third party facility, when service commences.

Delivery Charge: A component of the Rate Schedule through which the Company recovers its operating costs.

Demand Charge: A fixed monthly charge which is applied to the Contract Demand specified in a Service Contract.

Demand Overrun: The amount of gas taken at a Terminal Location exceeding the Contract Demand.

Direct Purchase: Natural gas supply purchase arrangements transacted directly between the Applicant and one or more parties, including the Company.

Disconnect and Reconnect Charges: The charges levied by the Company for disconnecting or reconnecting an Applicant from or to the Company's distribution system.

Diversion: Delivery of gas on a day to a delivery point different from the normal delivery point specified in a Service Contract.

Firm Service: A service for a continuous delivery of gas without curtailment, except under extraordinary circumstances.

Firm Transportation ("FT"): Firm Transportation service offered by upstream pipelines to move gas from a receipt point to a delivery point, as defined by the pipeline.

Force Majeure: Any cause not reasonably within the control of the Company and which the Company cannot prevent or overcome with reasonable due diligence, including:

(a) physical events such as an act of God, landslide, earthquake, storm or storm warning such as a hurricane which results in evacuation of an affected area, flood, washout, explosion, breakage or accident to machinery or equipment or lines of pipe used to transport gas, the necessity for making repairs to or alterations of such machinery or equipment or lines of pipe or inability to obtain materials, supplies (including a supply of services) or permits required by the Company to provide service;

(b) interruption and/or curtailment of firm transportation by a gas transporter for the Company;

(c) acts of others such as strike, lockout or other industrial disturbance, civil disturbance, blockade, act of a public enemy, terrorism, riot, sabotage, insurrections or war, as well as physical damage resulting from the negligence of others;

(d) in relation to Load Balancing, failure or malfunction of any storage equipment or facilities of the Company; and

(e) governmental actions, such as necessity for compliance with any applicable laws.

Gas: Natural Gas.

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

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

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

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

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

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

Gigajoule ("GJ"): See Joule.

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

Imperial Conversion Factors:

Volume:		
1,000 cubic feet (cf)	=	1 Mcf
	=	28.32784 cubic metres (m^3)
1 billion cubic feet (cf)	=	28.32784 $10^6 m^3$
Pressure:		
1 pound force per square inch (p.s.i.)	=	6.894757 kilopascals (kPa)
1 inch Water Column (in W.C.) (60°F)	=	0.249 kPa (15.5°C)
1 standard atmosphere	=	101.325 kPa
Energy:		
1 million British thermal units	=	1 MMBtu
	=	1.055056 gigajoules (GJ)
948,213.3 Btu	=	1 GJ
Monetary Value:		
$1 per Mcf	=	$0.03530096 per m^3
$1 per MMBtu	=	$0.9482133 per GJ

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

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

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

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

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

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

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

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

Metric Conversion Factors:

Volume:		
1 cubic metre (m^3)	=	35.30096 cubic feet (cf)
1,000 cubic metres	=	10^3m^3
	=	35,300.96 cf
	=	35.30096 Mcf
28.32784 m^3	=	1 Mcf
Pressure:		
1 kilopascal (kPa)	=	1,000 pascals
	=	0.145 pounds per square inch (p.s.i.)
101.325 kPa	=	one standard atmosphere
Energy:		
1 megajoule (MJ)	=	1,000,000 joules
	=	948.2133 British thermal units (Btu)
1 gigajoule (GJ)	=	948,213.3 Btu
1.055056 GJ	=	1 MMBtu
Monetary Value:		
$1 per 10^3m^3	=	$0.02832784 per Mcf
$1 per gigajoule	=	$1.055056 per MMBtu

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

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

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

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

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

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

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

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

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

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

T-Service: Transportation Service.

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

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

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

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

RATES AND SERVICES AVAILABLE

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

SECTION A - INTRODUCTION

1. In Franchise Services

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

Applicants may elect to have the Company provide all-inclusively the services which are mutually agreed to be required or they may select (from the 300 series of rates, and Rate 125) only the amounts of those services which they consider they need.

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

Service to residential locations is provided pursuant to Rate 1.

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

2. Ex-Franchise Services

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

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

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

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

SECTION B - DIRECT PURCHASE ARRANGEMENTS

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

B. Western Canada

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

C. Ontario Delivery T-Service Arrangements

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

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

(i) Bundled T-Service

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

(ii) Unbundled T-Service

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

D. Western Delivery T-Service Arrangement

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

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

PART III

TERMS AND CONDITIONS APPLICABLE TO ALL SERVICES

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

SECTION A - AVAILABILITY

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

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

SECTION B - ENERGY CONTENT

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

SECTION C - SUBSTITUTION PROVISION

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

SECTION D - BILLS

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

SECTION E - MINIMUM BILLS

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

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

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

SECTION F - PAYMENT CONDITIONS

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

SECTION G - TERM OF ARRANGEMENT

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

SECTION H - RESALE PROHIBITION

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

SECTION I - MEASUREMENT

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

SECTION J - RATES IN CONTRACTS

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

SECTION K - ADVICE RE: CURTAILMENT

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

SECTION L - DAILY DELIVERED VOLUMES

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

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

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

SECTION M - AUTHORIZED OVERRUN GAS

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

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

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

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

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

plus

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

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

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

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

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

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

SECTION O – COMPANY RESPONSIBILTY AND LIABILITY

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

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

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

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

PART IV

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

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

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

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

SECTION A - NOMINATIONS

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

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

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

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

SECTION B - OBLIGATION TO DELIVER

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

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

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

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

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

SECTION C - DIVERSION RIGHTS

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

SECTION D - BANKED GAS ACCOUNT (BGA)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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	**$20.00**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**8.3151 ¢/m³**
For the next 55 m³ per month	**7.8351 ¢/m³**
For the next 85 m³ per month	**7.4591 ¢/m³**
For all over 170 m³ per month	**7.1791 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.6560 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

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

RATE:

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

		Billing Month January to December
Monthly Customer Charge		**$70.00**
Delivery Charge per cubic metre		
For the first	500 m³ per month	**7.8604 ¢/m³**
For the next	1050 m³ per month	**6.1854 ¢/m³**
For the next	4500 m³ per month	**5.0128 ¢/m³**
For the next	7000 m³ per month	**4.2591 ¢/m³**
For the next	15250 m³ per month	**3.9242 ¢/m³**
For all over	28300 m³ per month	**3.8404 ¢/m³**
Transportation Charge per cubic metre		**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)		**13.7033 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") 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	**$240.87**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**10.8635 ¢/m³**
For all over 20,000 m³ per month	**10.1687 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5585 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified annual volume of natural gas of not less than 340,000 cubic metres to be delivered at a specified maximum daily rate.

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$122.01**
Delivery Charge	
Per cubic metre of Contract Demand	**8.1900 ¢/m³**
For the first 14,000 m³ per month	**5.1024 ¢/m³**
For the next 28,000 m³ per month	**3.7434 ¢/m³**
For all over 42,000 m³ per month	**3.1844 ¢/m³**
Gas Supply Load Balancing Charge	**0.4882 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5610 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

MINIMUM BILL:

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

11.2358 ¢/m³

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 183 times a specified maximum daily volume of not less than 1,865 cubic metres.

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$587.37**
Delivery Charge	
Per cubic metre of Contract Demand	**22.9100 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5810 ¢/m³**
For all over 1,000,000 m³ per month	**0.4310 ¢/m³**
Gas Supply Load Balancing Charge	**0.1353 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5585 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

MINIMUM BILL:

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

6.3615 ¢/m³

In determining the Annual Volume Deficiency, the minimum bill multiplier shall not be less than 183.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$622.62**
Delivery Charge	
Per cubic metre of Contract Demand	**24.3600 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.2405 ¢/m³**
For all over 1,000,000 m³ per month	**0.1405 ¢/m³**
Gas Supply Load Balancing Charge	**0.0507 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**0.0224 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

MINIMUM BILL:

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

5.9364 ¢/m³

In determining the Annual Volume Deficiency the minimum bill multiplier shall not be less than 292.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified maximum daily volume of natural gas. The maximum daily volume for billing purposes, Contract Demand or Billing Contract Demand, as applicable, shall not be less than 600,000 cubic metres. The Service under this rate requires Automatic Meter Reading (AMR) capability.

CHARACTER OF SERVICE:

Service shall be firm except for events specified in the Service Contract including force majeure.

For Non-Dedicated Service the monthly demand charges payable shall be based on the Contract Demand which shall be 24 times the Hourly Demand and the Applicant shall not exceed the Hourly Demand.

For Dedicated Service the monthly demand charges payable shall be based on the Billing Contract Demand or the Contract Demand specified in the Service Contract. The Applicant shall not exceed an hourly flow calculated as 1/24th of the Contract Demand specified in the Service Contract.

DISTRIBUTION RATES:

The following rates and charges, as applicable, shall apply for deliveries to the Terminal Location.

Monthly Customer Charge	**$500.00**
Demand Charge	
Per cubic metre of the Contract Demand or the Billing Contract Demand, as applicable, per month	**9.1914 ¢/m³**
Direct Purchase Administration Charge	**$75.00**
Forecast Unaccounted For Gas Percentage	**0.3%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a). In the case of a Dedicated Service, the Unaccounted for Gas volume requirement is not applicable.

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG. Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 125 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

   Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA) or other Delivery Area as specified in the applicable Service Contract. The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed the Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 125 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

The Company permits pooling of Rate 125 contracts for legally related customers who meet the Business Corporations Act (Ontario) ("OBCA") definition of "affiliates" to allow for the management of those contracts by a single manager. The single manager is jointly liable with the individual customers for all of their obligations under the contracts, while the individual customers are severally liable for all of their obligations under their own contracts.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery (the sum of the customer's Contract Demand and the authorized overrun amount) required to serve the customer's daily load, plus the UFG. In the event that gas usage exceeds the gas delivery on a day where demand overrun is authorized, the excess gas consumption shall be deemed Supply Overrun Gas.
Such service shall not exceed 5 days in any contract year. Based on the terms of the Service Contract, requests beyond 5 days will constitute a request for a new Contract Demand level with retroactive charges. The new Contract Demand level may be restricted by the capability of the local distribution facilities to accommodate higher demand.

Automatic authorization of transportation overrun over the Billing Contract Demand will be given in the case of Dedicated Service to the Terminal Location provided that pipeline capacity is available and subject to the Contract Demand as specified in the Service Contract.

Authorized Demand Overrun Rate	**0.30 ¢/m³**

The Authorized Demand Overrun Rate may be applied to commissioning volumes at the Company's sole discretion, for a contractual period of not more than one year, as specified in the Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas may establish a new Contract Demand effective immediately and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Based on capability of the local distribution facilities to accommodate higher demand, different conditions may apply as specified in the applicable Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below***.**

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following day's Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule, including the load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location or at the location of the meter installation for a customer served from a dedicated facility. In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources including where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed the Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA), or other Delivery Area as specified in the applicable Service Contract.

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's Terminal Location or in the event of combined nominations at the Terminal Locations specified.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance:

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery since the date the customer last balanced or was deemed to have balanced its Cumulative Imbalance account.

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand for non dedicated service and 60% of the Billing Contract Demand for dedicated service.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = 0.7497 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 0.8996 cents/m3 applied to Daily Imbalance of greater than 10% but less than the Maximum Contractual Imbalance

In addition for Tier 2, instances where the Daily Imbalance represents an under delivery of gas during the winter season shall constitute Unauthorized Supply Overrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. Where the Daily Imbalance represents an over delivery of gas during the summer season, the Company reserves the right to deem as Unauthorized Supply Underrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. The Company will issue a 24-hour advance notice to customers of its intent to impose cash out for over delivery of gas during the summer season.

For customers delivering to a Primary Delivery Area other than EGD's CDA or EGD's EDA, the Tier 1 Fee is applied to Daily Imbalance of greater than 0% but less than 10% of the Maximum Contractual Imbalance

The customers shall also pay any Limited Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rates 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances. The Company will provide the customer with a derivation of any such charges.

Customer’s Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer’s Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area. Customers may also nominate to transfer gas from their Cumulative Imbalance Account into an unbundled (Rate 315 or Rate 316) storage account of the customer subject to their storage contract parameters.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed the Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds the Contract Demand.

The customer’s Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. In the event that the customer's imbalance exceeds their Maximum Contractual Imbalance the Company shall deem the excess imbalance to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee, applicable daily, is 1.0618 cents/m3 per unit of imbalance.

In addition, on any day that the Company declares an Operational Flow Order, negative Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance in the winter season shall be deemed to be Unauthorized Overrun Gas. The Company reserves the right to deem positive Cumulative Imbalances greater than 10% of Maximum Contractual Imbalance in the summer season as Unauthorized Supply Underun Gas. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders including cash out instructions for Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 340,000 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure. A maximum of five percent of the contracted annual volume may be taken by the Applicant in a single month during the months of December to March inclusively.

RATE:

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

	Billing Month	
	December to March	**April to November**
Monthly Customer Charge	**$115.08**	**$115.08**
Delivery Charge		
For the first 14,000 m³ per month	**6.7507 ¢/m³**	**2.0507 ¢/m³**
For the next 28,000 m³ per month	**5.5507 ¢/m³**	**1.3507 ¢/m³**
For all over 42,000 m³ per month	**5.1507 ¢/m³**	**1.1507 ¢/m³**
Gas Supply Load Balancing Charge	**0.0000 ¢/m³**	**0.0000 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.6347 ¢/m³**	**13.6347 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

RATE NUMBER: **135**

SEASONAL CREDIT:

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

SEASONAL OVERRUN CHARGE:

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

Seasonal Overrun Charges:

December and March	**24.8738 ¢/m³**
January and February	**62.1845 ¢/m³**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **9.2626 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$123.34**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.8001 ¢/m³**
For the next 28,000 m³ per month	**1.4411 ¢/m³**
For all over 42,000 m³ per month	**0.8821 ¢/m³**
Gas Supply Load Balancing Charge	**0.2104 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.7248 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

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

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**8.6557 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

RATE NUMBER: **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 reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source.
The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month
	January to December
Monthly Customer Charge	**$280.16**
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	**0.5183 ¢/m³**
For all over 1,000,000 m³ per month	**0.3183 ¢/m³**
Gas Supply Load Balancing Charge	**0.1194 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5585 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

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

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **6.2829 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

To any Distributor who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of an annual supply of natural gas to customers outside of the Company's franchise area.

CHARACTER OF SERVICE:

Service shall be continuous (firm), except for events as specified in the Service Contract including force majeure, up to the contracted firm daily demand and subject to curtailment or discontinuance, of demand in excess of the firm contract demand, upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

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

	Billing Month January to December
Monthly Customer Charge	
The monthly customer charge shall be negotiated with the applicant and shall not exceed:	**$2,000.00**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**14.7000 ¢/m³**
Per cubic metre of gas delivered	**1.2519 ¢/m³**
Gas Supply Load Balancing Charge	**0.5684 ¢/m³**
Transportation Charge per cubic metre	**5.6862 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**13.5585 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**13.5361 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

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

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**7.4655 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY:

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

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

CHARACTER OF SERVICE:

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

DISTRIBUTION RATES:

Monthly Customer Charge	**$500.00**
Monthly Contract Demand Charge Firm	**25.2334 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3626 ¢/m³**
Maximum Delivery Charge	**0.9955 ¢/m³**
Direct Purchase Administration Charge	**$75.00**
Forecast Unaccounted For Gas Percentage	**0.3%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Contract Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a).

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG, net of No-Notice Storage Service provisions under Rate 315, if applicable. The amount of gas delivered under No-Notice Storage Service will also be reduced by the UFG adjustment factor for delivery to the customer's meter.

   Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 300 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA) *or* other Delivery Area as specified in the applicable Service Contract. The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 300 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery required to serve the customer's daily load, including quantities of gas in excess of the Contract Demand, plus the UFG. The Load Balancing Provisions and/or No-Notice Storage Service provisions under Rate 315 cannot be used for Authorized Demand Overrun. Failure to nominate gas deliveries to match Authorized Demand Overrun shall constitute Unauthorized Supply Overrun.

The rate applicable to Authorized Demand Overrun shall equal the applicable Monthly Demand Charge times 12/365 provided, however, that such service shall not exceed 5 days in any contract year. Requests beyond 5 days will constitute a request for a new Contract Demand level, with retroactive charges based on terms of Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas will establish a new Contract Demand and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions. Where a customer receives interruptible service hereunder and consumes gas during a period of interruption, such gas shall be deemed Unauthorized Supply Overrun. In addition to charges for Unauthorized Supply Overrun, interruptible customers consuming gas during a scheduled interruption shall pay a penalty charge of $18.00 per m3.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below*.

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable Rate 300 Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following days Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule, including interruptible service and load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

Load Balancing:

Any difference between actual daily-metered consumption and the actual daily volume of gas delivered to the system less the UFG shall first be provided under the provisions of Rate 315 - Gas Storage Service, if applicable. Any remaining difference will be subject to the Load Balancing Provisions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location.

In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources plus, where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA), or other Delivery Area as specified in the applicable Service Contract.

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's premise.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance:

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery.

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance and shall be subject to a charge of 0.7497 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 0.8996 cents/m3

The customers shall also pay any Limited Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rate 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances.

A Daily Imbalance in excess of the Maximum Contractual Imbalance shall be deemed to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

Customer's Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer's Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds Contract Demand.

The customer's Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. The excess imbalance shall be deemed to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee, applicable daily, is 0.684 cents/m3 per unit of imbalance.

The customer's Cumulative Imbalance shall be equal to zero within five (5) days from the last day of the Service Contract.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

APPLICABILITY:

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

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

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

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

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

CHARACTER OF SERVICE:

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

The service is available on two bases:

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

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

RATE:

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

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0567 ¢/m³**
Monthly Storage Deliverability Demand Charge	**16.1123 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.3383 ¢/m³**

Monthly Minimum Bill: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

FUEL RATIO REQUIREMENT:

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

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations and No-Notice Storage Service quantities.

All deemed withdrawal quantities under the No-Notice Storage Service provisions of this rate will be adjusted for the UFG provisions applicable to the distribution service rates.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

TERMS AND CONDITIONS OF SERVICE:

1. **Nominated Storage Service**:

Nominations under this rate shall only be accepted at the standard North American Energy Standards Board ("NAESB") nomination windows. The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to the applicable Primary Delivery Area, which may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA). All volumes nominated from storage are delivered first for purposes of daily Load Balancing of available supply assets. When system conditions permit, the customer may nominate all or a portion of the available withdrawal capacity for delivery to Dawn or to the customer's Primary Delivery Area for purposes other than consumption at the customer's own meter.

Storage not nominated for delivery will be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's Contract Demand (CD).

The customer may also nominate gas for delivery into storage by nominating the storage delivery area as the Primary Delivery Area. Gas nominated for storage delivery will not be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's CD.
Any gas in excess of the contract demand will be subject to cash out as injection overrun gas.

The Company reserves the right to limit injection and withdrawal rights to all storage customers in certain situations, such as major maintenance or construction projects, and may reduce nominations for injections and withdrawals over and above applicable storage ratchets. The Company will provide customers with one week's notice of its intent to limit injection and withdrawal rights, and at the same time, shall provide its best estimate of the duration and extent of the limitations.

In situations where the Company limits injection and withdrawal rights, the Company shall proportionately reduce the Storage Deliverability/Injection Demand Charge for affected customers based on the number of days the limitation is in effect and the difference between Deliverability/Injection Demand, subject to applicable storage ratchets, and the quantity of gas actually delivered or injected.

2. **No-Notice Storage Service**:

The Company, at its sole discretion based on operating conditions, may provide a No-Notice Storage Service that allows customers taking gas under distribution service rates to balance daily deliveries using this Storage Service. No-Notice Storage Service requires that the customer grant the Company the exclusive right to use unscheduled service available from storage to reduce the daily imbalance associated with the actual consumption of the customer.

No-Notice Storage Service is limited to the available, unscheduled withdrawal or injection capacity under contract to serve a customer. Where the customer serves multiple delivery locations from a single storage Service Contract, the customer shall specify the order in which gas is to be delivered to each Terminal Location served under a distribution Service Contract. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location.

The availability of No-Notice Storage Service is subject to and reduced by any service schedule from or to storage. To the extent that the quantity of gas available in storage is insufficient to meet the requirements of the customer under a No-Notice Storage Service, the customer will be unable to use the service on a no-notice basis for Load Balancing service. To the extent that the scheduled injections into storage plus No-Notice Storage Service exceed the maximum limit for injection, No-Notice Storage Service will be reduced and the remainder of the gas will constitute a daily imbalance. Gas delivered in excess of the maximum injection quantity shall be deemed injection overrun gas and cashed out at 50% of the lowest index price of gas.

Other provisions:

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its own gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

APPLICABILITY:

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

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

The maximum hourly injections / withdrawals shall equal 1/24th 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	**0.0567 ¢/m³**
Monthly Storage Deliverability Demand Charge	**5.1445 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.1049 ¢/m³**

Monthly Minimum Bill: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

FUEL RATIO REQUIREMENT:

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

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

TERMS AND CONDITIONS OF SERVICE:

Nominated Storage Service:

The customer shall nominate storage injections and withdrawals daily. The customer may change daily nominations based on the nomination windows within a day as defined by the customer contract with Union Gas Limited and TransCanada PipeLines (TCPL).

The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to the applicable Primary Delivery Area.

The Company reserves the right to limit injection and withdrawal rights to all storage customers in certain situations, such as major maintenance or construction projects, and may reduce nominations for injections and withdrawals over and above applicable storage ratchets. The Company will provide customers with one week's notice of its intent to limit injection and withdrawal rights, and at the same time, shall provide its best estimate of the duration and extent of the limitations.

In situations where the Company limits injection and withdrawal rights, the Company shall proportionately reduce the Storage Deliverability/Injection Demand Charge for affected customers based on the number of days the limitation is in effect and the difference between Deliverability/Injection Demand, subject to applicable storage ratchets, and the quantity of gas actually delivered or injected.

The customer may transfer the title of gas in storage.

Other provisions:

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its own gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

RATE NUMBER: **320**	**BACKSTOPPING SERVICE**

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month
	January to December
Gas Supply Charge	
Per cubic metre of gas sold	**19.6823 ¢/m³**

provided that if upon the request of an Applicant, the Company quotes a rate to apply to gas which is delivered to the Applicant at a particular Terminal Location on a particular day or days and to which this Rate Schedule is applicable (which rate shall not be less than the Company's avoided cost in the circumstances at the time nor greater than the otherwise applicable rate specified above), then the Gas Supply Charge applicable to such gas shall be the rate quoted by the Company.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2012 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296, effective October 1, 2011.

APPLICABILITY AND CHARACTER OF SERVICE:

Service under this rate schedule shall apply to the Transmission and Compression Service Agreement with Union Gas Limited dated April 1, 1989, and the Transmission, Compression and Pool Storage Service Agreement with Centra Gas Ontario Inc. dated May 30, 1994. Service shall be provided subject to the terms and conditions specified in the Service Agreement.

RATE:

The Customer shall pay for service rendered in each month in a contract year, the sum of the following applicable charges:

	Transmission & Compression $\$/10^3m^3$	**Pool Storage $\$/10^3m^3$**
Demand Charge for:		
Annual Turnover Volume	**0.1916**	**0.2273**
Maximum Daily Withdrawal Volume	**17.3202**	**20.6179**
Commodity Charge	**0.9654**	**0.3242**

FUEL RATIO REQUIREMENT:

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

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges as stated in Rate Section above.

EXCESS VOLUME AND OVERRUN RATES:

In addition to the charges provided for in the Rate Section above, the Customer shall pay, for services rendered, the sum of the following applicable charges as they are incurred:

TERMS AND CONDITIONS OF SERVICE:

1. Excess Volumes will be billed at the total of the Excess Volume Charges as stated above.

2. Transmission and Compression, and Pool Storage Overrun Service will be billed according to the following:
   (a) At the end of each month, in a contract year, the Company will make a determination, for each day in the month, of

      (i) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account into the Company System, at the Point of Delivery and the Customer's Maximum Daily Injection Volume, and

      (ii) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account from the Company System, at the Point of Delivery, and the Customer's Maximum Daily Withdrawal Volume.

	Excess Volume Charge $/10³m³ / Year	Overrun Charge $/10³m³ / Day
Transmission & Compression		
Authorized	**2.5288**	**0.5694**
Unauthorized	**-**	**228.6263**
Pool Storage		
Authorized	**3.0004**	**0.6778**
Unauthorized	**-**	**272.1560**

(b) For each day of the month, where any such differences exceed 2.0 percent of the Customer's relevant Maximum Daily Injection Volume and/or Maximum Daily Withdrawal Volume, the Customer shall pay a charge equal to the relevant Overrun rates, as stated above, for such differences.

BILLING ADJUSTMENT:

1. Injection deficiency - If at the beginning of any Withdrawal Period the Customer's Storage Balance is less than the Customer's Annual Turnover Volume, due solely to the Company's inability to inject gas for any reason other than the fault of the Customer, then the applicable Demand Charge for Annual Turnover Volume for the contract year beginning the prior April 1 as stated in Rate Section as applicable, shall be adjusted by multiplying each by a fraction, the numerator of which shall be the Customer's Storage Gas Balance as of the beginning of such Withdrawal Period and the denominator shall be the Customer's Annual Turnover Volume as it may have been established for the then current year.

2. Withdrawal deficiency - If in any month in a contract year for any reason other than the fault of the Customer, the Company fails or is unable to deliver during any one or more days, the amount of gas which the Customer has nominated, up to the maximum volumes which the Company is obligated by the Agreement to deliver to the Customer, then the Demand Charge for maximum Contract Daily Withdrawal Volume in the contract year otherwise payable for the month in which such failure occurs, as stated in Rate Section above, as applicable, shall be reduced by an amount for each day of deficiency to be calculated as follows: The Demand Charge for maximum Contract Daily Withdrawal Volume for the contract year for the month will be divided by 30.4 and the result obtained will then be multiplied by a fraction, the numerator being the difference between the nominated volume for such day and the delivered volume for such day and the denominator being the Customer's maximum Contract Daily Withdrawal Volume for such contract year.

TERMS AND EXPRESSIONS:

In the application of this Rate Schedule to each of the Agreements, terms and expressions used in this Rate Schedule have the meanings ascribed thereto in such Agreement.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

RATE NUMBER: **330**	**TRANSMISSION AND COMPRESSION AND POOL STORAGE**

APPLICABILITY:

To any Applicant who enters into a Storage Contract with the Company for delivery by the Applicant to the Company and re-delivery by the Company to the Applicant of a volume of natural gas owned by the Applicant.

CHARACTER OF SERVICE:

Service under this rate is for Full Cycle or Short Cycle storage service; with firm or interruptible injection and withdrawal service, all as may be available from time to time.

RATE:

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

	Full Cycle		**Short Cycle**
	Firm	**Interruptible**	
	$/10³m³	**$/10³m³**	**$/10³m³**
Monthly Demand Charge per unit of Annual Turnover Volume:			
Minimum	**0.4189**	**0.4189**	**-**
Maximum	**2.0945**	**2.0945**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**37.9381**	**30.3505**	**-**
Maximum	**189.6905**	**151.7524**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**1.2896**	**1.2896**	**0.6771**
Maximum	**6.4480**	**6.4480**	**38.9530**

FUEL RATIO REQUIREMENT:

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

TRANSACTING IN ENERGY:

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

MINIMUM BILL:

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

OVERRUN RATES:

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

	Full Cycle		Short Cycle
	Firm	**Interruptible**	
	$/10³m³	**$/10³m³**	**$/10³m³**
Authorized Overrun			
Annual Turnover Volume			
Negotiable, not to exceed:	**38.9530**	**38.9530**	**38.9530**
Authorized Overrun			
Daily Injection/Withdrawal			
Negotiable, not to exceed:	**38.9530**	**38.9530**	**38.9530**
Unauthorized Overrun			
Annual Turnover Volume			
Excess Storage Balance			
September 1 - November 30	**389.5305**	**389.5305**	**389.5305**
December 1 - October 31	**38.9530**	**38.9530**	**38.9530**
Unauthorized Overrun			
Annual Turnover Volume			
Negative Storage Balance			

TERMS AND CONDITIONS OF SERVICE:

1. All Services are available at the Company's sole discretion.

2. Delivery and Re-delivery of the volume of natural gas shall be from/to the facilities of Union Gas Limited and / or TransCanada PipeLines Limited in Dawn Township and/or Niagara Gas Transmission Limited in Moore Township.

3. The Customers daily injections or withdrawals will be adjusted to provide for the fuel ratio stated in the Fuel Ratio Section. In the event that a Short Cycle service does not require fuel for injection and/or withdrawal, the fuel ratio commodity charge may be waived.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

APPLICABILITY:

To any Applicant who enters into an agreement with the Company pursuant to the Rate 331 Tariff (“Tariff”) for transportation service on the Company’s pipelines extending from Tecumseh to Dawn (“Tecumseh Pipeline”). The Company will receive gas at Tecumseh and deliver the gas at Dawn. Capitalized terms used in this Rate Schedule shall have the meanings ascribed to those terms in the Tariff.

CHARACTER OF SERVICE:

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

RATE:

The following rates, effective January 1, 2012, shall apply in respect of FT and IT Service under this Rate Schedule:

	Demand Rate $\$/10^3m^3$	**Commodity Rate** $\$/10^3m^3$
FT Service	**5.3030**	**-**
IT Service	**-**	**0.2090**

FT Service: The monthly demand charge shall be the products obtained by multiplying the applicable Maximum Daily Volume by the above demand rate.

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

TERMS AND CONDITIONS OF SERVICE:

The terms and conditions of FT and IT Service are set out in the Tariff. The provisions of PARTS I to IV of the Company's HANDBOOK OF RATES AND DISTRIBUTION SERVICES do not apply to Rate 331 service.

EFFECTIVE DATE:

The Tariff was approved by the Board in Board Order EB-2010-0177, dated July 12, 2010, and is posted and available on the Company's website. In accordance with Section 1.6.2 of the Board's Storage and Transportation Access Rule, the Tariff does not apply to any Rate 331 service agreements executed prior to June 16, 2010.

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

The Town of Collingwood
The Town of Midland

APPLICABILITY:

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

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00	per month
Account Charge	$0.21	per month per account

AVERAGE COST OF TRANSPORTATION:

The average cost of transportation effective January 1, 2012:

Point of Acceptance	Firm Transportation (FT)
CDA, EDA	5.6862 ¢/m³

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

APPLICABILITY:

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

TERMS AND CONDITIONS OF SERVICE:

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

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

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

   or

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

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

APPLICABILITY:

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

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00	per month
Account Charge	$0.21	per month per account

BUY / SELL PRICE:

In Buy/Sell Arrangements between the Company and an Applicant, the Company shall buy the Applicants gas at the Company's actual FT-WACOG price determined on a monthly basis in the manner approved by the Ontario Energy Board. For Western Buy/Sell arrangements the FT-WACOG price shall be reduced by pipeline transmission costs.

FT FUEL PRICE:

The FT fuel price used to establish the Buy price in Western Buy/Sell arrangements without fuel will be determined monthly based upon the actual FT-WACOG.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2012. This rate schedule is effective January 1, 2012 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2011 and that indicates as the Board Order, EB-2011-0296 effective October 1, 2011.

RIDER: C	GAS COST ADJUSTMENT RIDER

The following adjustment is applicable to all gas sold or delivered during the period of January 1, 2012 to .

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

RIDER: **C**

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

RIDER: **C**

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

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

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

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

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

APPLICABILITY:

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

IN FRANCHISE TITLE TRANSFER SERVICE:

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

The Company will not apply an Administration charge for transfers between pools that have similar Points of Acceptance (i.e. both Ontario or both Western Points of Acceptance). For transfers between pools that have dissimilar Points of Acceptance (i.e. one an Ontario and one a Western Point of Acceptance), the Company will apply the following Administration Charge per transaction to the Applicant transferring the natural gas (i.e. the seller or transferor).

Administration Charge:	$169.00	per transaction

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to an Applicant with an Ontario Point of Acceptance. The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from an Applicant with an Ontario Point of Acceptance.

ENHANCED TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, the Applicant may elect to initiate a transfer of natural gas between the Company and another utility, regulated by the Ontario Energy Board, at Dawn for the purposes of reducing an imbalance between the customer's deliveries and consumption within the Enbridge Gas Distribution franchise areas. The ability of the Company to accept such an election may be constrained at various points in time for customers obtaining services under any rate other than Rate 125 or 300 due to operational considerations of the Company.

The cost for this service is separated between an Adminstration Charge that is applicable to all Applicants and a Bundled Service Charge that is only applicable to Applicants obtaining services under any rate other than Rate 125 or 300.

Administration Charge:

Base Charge	$50.00	per transaction
Commodity Charge	$0.6448	per 10^3m^3

Bundled Service Charge:
The Bundled Service Charge shall be equal to the absolute difference between the Eastern Zone and Southwest Zone Firm Transportation tolls approved by the National Energy Board for TCPL at a 100% Load Factor.

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to another party. The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from another party.

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)

ITEM NO.	RATE NO.	Col. 1 DISTRIBUTION	Col. 2 TRANSPORT	Col. 3 GAS SUPPLY LOAD BAL	Col. 4 GAS SUPPLY COMMODITY	Col. 5 TOTAL
		REVENUE -EB-2011-0277 RATES				
1.	1	743,083	227,622	39,665	504,344	1,514,715
2.	6	334,151	191,613	35,767	359,106	920,638
3.	9	152	58	0	139	350
4.	100	0	0	0	0	0
5.	110	10,631	9,101	660	8,714	29,106
6.	115	6,322	569	270	0	7,161
7.	125	9,786	0	0	0	9,786
8.	135	916	1,233	(465)	84	1,767
9.	145	3,345	2,409	(521)	2,932	8,165
10.	170	4,373	3,254	(5,647)	6,736	8,715
11.	200	4,033	7,014	726	16,725	28,498
12.	300	384	0	0	0	384
13.	SUB-TOTAL	1,117,177	442,874	70,455	898,780	2,529,286
14.	STORAGE	1,619	0	0	0	1,619
15.	DPAC	2,218	0	0	0	2,218
16.	TOTAL	1,121,014	442,874	70,455	898,780	2,533,123

Witnesses: J. Collier
A. Kacicnik

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

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
		DISTRIBUTION			GAS SUPPLY TRANSPORTATION			GAS SUPPLY LOAD BALANCING			GAS SUPPLY COMMODITY			TOTAL
ITEM NO.	RATE NO.	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	REVENUES
		10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	$000
1.	1	4,583,338	743,083	16.21	4,003,100	227,622	5.69	4,583,338	39,665	0.87	3,693,205	504,344	13.66	1,514,715
2.	6	4,772,169	334,151	7.00	3,369,817	191,613	5.69	4,772,169	35,767	0.75	2,620,584	359,106	13.70	920,638
3.	9	1,177	152	12.95	1,027	58	5.69	1,177	0	0.00	1,027	139	13.56	350
4.	100	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0
5.	110	488,031	10,631	2.18	160,062	9,101	5.69	488,031	660	0.14	64,267	8,714	13.56	29,106
6.	115	532,453	6,322	1.19	10,015	569	5.69	532,453	270	0.05	0	0	0.00	7,161
7.	125	0	9,786	0.00	0	0	0.00	0	0	0.00	0	0	0.00	9,786
8.	135	55,183	916	1.66	21,679	1,233	5.69	55,183	(465)	(0.84)	613	84	13.63	1,767
9.	145	154,354	3,345	2.17	42,372	2,409	5.69	154,354	(521)	(0.34)	21,365	2,932	13.72	8,165
10.	170	519,974	4,373	0.84	57,218	3,254	5.69	519,974	(5,647)	(1.09)	49,679	6,736	13.56	8,715
11.	200	162,216	4,033	2.49	123,354	7,014	5.69	162,216	726	0.45	123,354	16,725	13.56	28,498
12.	300	31,049	384	0.00	0	0	0.00	0	0	0.00	0	0	0.00	384
13	SUB-TOTAL	11,299,945	1,117,177	9.89	7,788,644	442,874	5.69	11,268,896	70,455	0.63	6,574,095	898,780	13.67	2,529,286
14.	STORAGE	N/A	1,619	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,619
15.	DPAC	N/A	2,218	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	2,218
16.	TOTAL	11,299,945	1,121,014	9.89	7,788,644	442,874	5.69	11,268,896	70,455	0.63	6,574,095	898,780	13.67	2,533,123

Witnesses: J. Collier
A. Kacicnik

REVENUE - PROPOSED METHODOLOGY BY RATE CLASS

	Col. 1	Col. 2	Col. 3	Col. 4
		REVENUE -EB-2011-0277 RATES		
Item No.	Rate No.	Proposed Revenue ($000)	Unbilled Revenue ($000)	Total ($000)
1.	1	1,514,715	1,763	1,516,478
2.	6	920,638	5,019	925,657
3.	9	350	0	350
4.	100	0	0	0
5.	110	29,106	218	29,324
6.	115	7,161	18	7,179
7.	125	9,786	0	9,786
8.	135	1,767	2	1,769
9.	145	8,165	162	8,328
10.	170	8,715	83	8,797
11.	200	28,498	0	28,498
12.	300	384	0	384
13.	SUB-TOTAL	2,529,286	7,264	2,536,550
14.	STORAGE	1,619	0	1,619
15.	DPAC	2,218	0	2,218
16.	TOTAL	2,533,123	7,264	2,540,387

Witnesses: J. Collier
A. Kacicnik

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

Item No.	Rate No.	Col. 1	Col. 2 Rate Block m³		Col. 3 EB-2011-0296 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2011-0277 cents *
	RATE 1						
1.01		Customer Charge			$19.00	$1.00	$20.00
1.02		Delivery Charge	first	30	7.3312	0.1185	7.4497
1.03			next	55	6.8589	0.1108	6.9697
1.04			next	85	6.4889	0.1049	6.5937
1.05			over	170	6.2133	0.1004	6.3137
1.06		Gas Supply Load Balancing			0.9566	(0.0911)	0.8654
1.07		Gas Supply Transportation			5.7181	(0.0319)	5.6862
1.08		Gas Supply Commodity - System			13.6891	(0.0331)	13.6560
1.09		Gas Supply Commodity - Buy/Sell			13.6668	(0.0332)	13.6336
	RATE 6						
2.01		Customer Charge			$65.00	$5.00	$70.00
2.02		Delivery Charge	First 500		7.0056	0.1053	7.1109
2.03			Next 1050		5.3554	0.0805	5.4359
2.04			Next 4500		4.2001	0.0631	4.2633
2.05			Next 7000		3.4576	0.0520	3.5096
2.06			Next 15250		3.1277	0.0470	3.1747
2.07			Over 28300		3.0451	0.0458	3.0909
2.08		Gas Supply Load Balancing			0.8574	(0.1079)	0.7495
2.09		Gas Supply Transportation			5.7181	(0.0319)	5.6862
2.10		Gas Supply Commodity - System			13.7537	(0.0504)	13.7033
2.11		Gas Supply Commodity - Buy/Sell			13.7313	(0.0503)	13.6810
	RATE 9						
3.01		Customer Charge			$235.89	$4.98	$240.87
3.02		Delivery Charge	first	20000	10.7695	0.0903	10.8598
3.03			over	20000	10.0805	0.0845	10.1650
3.04		Gas Supply Load Balancing			0.0040	(0.0003)	0.0037
3.05		Gas Supply Transportation			5.7181	(0.0319)	5.6862
3.06		Gas Supply Commodity - System			13.5786	(0.0201)	13.5585
3.07		Gas Supply Commodity - Buy/Sell			13.5562	(0.0201)	13.5361
	RATE 100						
4.01		Customer Charge			$122.01	$0.00	$122.01
4.02		Demand Charge (Cents/Month/m³)			8.1900	0.0000	8.1900
4.03		Delivery Charge	first	14,000	5.1222	(0.0198)	5.1024
4.04			next	28,000	3.7632	(0.0198)	3.7434
4.05			over	42,000	3.2042	(0.0198)	3.1844
4.06		Gas Supply Load Balancing			0.5908	(0.1079)	0.4882
4.07		Gas Supply Transportation			5.7181	(0.0319)	5.6862
4.08		Gas Supply Commodity - System			13.6109	(0.0504)	13.5610
		Gas Supply Commodity - Buy/Sell			13.5944	(0.0503)	13.5446
	RATE 110						
5.01		Customer Charge			$587.37	$0.00	$587.37
5.02		Demand Charge (Cents/Month/m³)			22.9100	0.0000	22.9100
5.03		Delivery Charge	first	1,000,000	0.5945	(0.0135)	0.5810
5.04			over	1,000,000	0.4445	(0.0135)	0.4310
5.05		Load Balancing Commodity			0.1637	(0.0284)	0.1353
5.06		Gas Supply Transportation			5.7181	(0.0319)	5.6862
5.07		Gas Supply Commodity - System			13.5786	(0.0201)	13.5585
5.08		Gas Supply Commodity - Buy/Sell			13.5562	(0.0201)	13.5361

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2011-0296 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2011-0277 cents *
	RATE 115					
1.01		Customer Charge		$622.62	$0.00	$622.62
1.02		Demand Charge (Cents/Month/m³)		24.3600	0.0000	24.3600
1.03		Delivery Charge	first 1,000,000	0.3229	(0.0824)	0.2405
1.04			over 1,000,000	0.2229	(0.0824)	0.1405
1.05		Load Balancing Commodity		0.0545	(0.0038)	0.0507
1.06		Gas Supply Transportation		5.7181	(0.0319)	5.6862
1.07		Gas Supply Commodity - System		13.5786	(0.0201)	13.5585
1.08		Gas Supply Commodity - Buy/Sell		13.5562	(0.0201)	13.5361
	RATE 125					
2.01		Customer Charge		$ 500.00	$0.00	$ 500.00
2.02		Delivery Charge (Cents/Month/m³ of Contract Dmnd)		9.0792	0.1122	9.1914
	RATE 135	DEC - MAR				
3.00		Customer Charge		$115.08	$0.00	$115.08
3.01		Delivery Charge	first 14,000	6.7603	(0.0096)	6.7507
3.02			next 28,000	5.5603	(0.0096)	5.5507
3.03			over 42,000	5.1603	(0.0096)	5.1507
3.04		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.05		Gas Supply Transportation		5.7181	(0.0319)	5.6862
3.06		Gas Supply Commodity - System		13.6594	(0.0247)	13.6347
3.07		Gas Supply Commodity - Buy/Sell		13.6370	(0.0247)	13.6123
	RATE 135	APR - NOV				
3.08		Customer Charge		$115.08	$0.00	$115.08
3.09		Delivery Charge	first 14,000	2.0603	(0.0096)	2.0507
3.10			next 28,000	1.3603	(0.0096)	1.3507
3.11			over 42,000	1.1603	(0.0096)	1.1507
3.12		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.13		Gas Supply Transportation		5.7181	(0.0319)	5.6862
3.14		Gas Supply Commodity - System		13.6594	(0.0247)	13.6347
3.15		Gas Supply Commodity - Buy/Sell		13.6370	(0.0247)	13.6123
	RATE 145					
4.00		Customer Charge		$123.34	$0.00	$123.34
4.01		Demand Charge (Cents/Month/m³)		8.2300	0.000	8.2300
4.02		Delivery Charge	first 14,000	2.8051	(0.0050)	2.8001
4.03			next 28,000	1.4461	(0.0050)	1.4411
4.04			over 42,000	0.8871	(0.0050)	0.8821
4.05		Gas Supply Load Balancing		0.3557	(0.1453)	0.2104
4.06		Gas Supply Transportation		5.7181	(0.0319)	5.6862
4.07		Gas Supply Commodity - System		13.7438	(0.0190)	13.7248
4.08		Gas Supply Commodity - Buy/Sell		13.7214	(0.0189)	13.7025
	RATE 170					
5.00		Customer Charge		$279.31	$0.85	$280.16
5.01		Demand Charge (Cents/Month/m³)		4.0900	0.0000	4.0900
5.02		Delivery Charge	first 1,000,000	0.5168	0.0015	0.5183
5.03			over 1,000,000	0.3168	0.0015	0.3183
5.04		Gas Supply Load Balancing		0.1978	(0.0784)	0.1194
5.05		Gas Supply Transportation		5.7181	(0.0319)	5.6862
5.06		Gas Supply Commodity - System		13.5786	(0.0201)	13.5585
5.07		Gas Supply Commodity - Buy/Sell		13.5562	(0.0201)	13.5361

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2011-0296 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2011-0277 cents *
	RATE 200					
1.00		Customer Charge		$0.00	$0.00	$0.00
1.01		Demand Charge (Cents/Month/m³)		14.7000	0.0000	14.7000
1.02		Delivery Charge		1.1423	0.1096	1.2519
1.03		Gas Supply Load Balancing		0.6670	(0.0986)	0.5684
1.04		Gas Supply Transportation		5.7181	(0.0319)	5.6862
1.05		Gas Supply Commodity - System		13.5786	(0.0201)	13.5585
1.06		Gas Supply Commodity - Buy/Sell		13.5562	(0.0201)	13.5361
	RATE 300	FIRM SERVICE				
2.00		Monthly Customer Charge		$500.00	$0.00	$500.00
2.01		Demand Charge (Cents/Month/m³)		24.9253	0.3081	25.2334
		INTERRUPTIBLE SERVICE				
2.02		Minimum Delivery Charge (Cents/Month/m³)		0.3582	0.0044	0.3626
2.03		Maximum Delivery Charge (Cents/Month/m³)		0.9834	0.0121	0.9955
	RATE 315					
		Monthly Customer Charge		$150.00	$0.00	$150.00
3.00		Space Demand Chg (Cents/Month/m³)		0.0585	(0.0018)	0.0567
3.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		15.7936	0.3187	16.1123
3.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.3475	(0.0092)	0.3383
	RATE 320					
4.00		Backstop	All Gas Sold	19.8113	(0.1289)	19.6823
	RATE 316					
		Monthly Customer Charge		$150.00	$0.00	$150.00
5.00		Space Demand Chg (Cents/Month/m³)		0.0585	(0.0018)	0.0567
5.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		5.2711	(0.1266)	5.1445
5.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.1049	(0.0000)	0.1049

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2011-0296 cents *	Col. 4 Change cents *	Col. 5 EB-2011-0277 cents *
	RATE 325					
		Transmission & Compression				
1.00		Demand Charge - ATV ($/Month/10³ m³)		0.1870	0.0046	0.1916
1.01		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		16.9047	0.4155	17.3202
1.02		Commodity Charge		0.9660	(0.0006)	0.9654
		Storage				
1.03		Demand Charge - ATV ($/Month/10*3 m³)		0.2253	0.0020	0.2273
1.04		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		20.4355	0.1824	20.6179
1.05		Commodity Charge		0.3280	(0.0038)	0.3242
	RATE 330	Storage Service - Firm				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.00		Minimum		0.4123	0.0066	0.4189
2.01		Maximum		2.0615	0.0330	2.0945
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.02		Minimum		37.3402	0.5979	37.9381
2.03		Maximum		186.7010	2.9895	189.6905
		Commodity Charge				
2.04		Minimum		1.2940	(0.0044)	1.2896
2.05		Maximum		6.4700	($0.0220)	6.4480
		Storage Service - Interruptible				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.06		Minimum		0.4123	0.0066	0.4189
2.07		Maximum		2.0615	0.0330	2.0945
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.08		Minimum		29.8722	0.4783	30.3505
2.09		Maximum		149.3608	$2.3916	151.7524
		Commodity Charge				
2.10		Minimum		1.2940	(0.0044)	1.2896
2.11		Maximum		6.4700	(0.0220)	6.4480
		Storage Service - Off Peak				
		Commodity Charge				
2.12		Minimum		0.6752	0.0019	0.6771
2.13		Maximum		38.4629	0.4901	38.9530
	RATE 331	Tecumseh Transmission Service				
		Firm				
		Demand Charge ($/Month/10³ m³ of				
3.00		Maximum Contracted Daily Delivery)		5.2700	0.0330	5.3030
		Interruptible				
3.01		Commodity Charge ($/10³m³ of gas delivered)		0.2080	0.0010	0.2090

NOTE : * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

CALCULATION OF GAS SUPPLY CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF GAS SUPPLY CHARGE												
	GAS SUPPLY COSTS ($000)												
1.1	Annual Commodity	888,719	499,266	354,264	139	-	8,688	-	83	2,888	6,716	16,676	
1.2	Bad Debt Commodity	7,430	3,599	3,795	-	-	-	-	0	36	-	-	
1.3	System Gas Fee	1,472	827	587	0	-	14	-	0	5	11	28	
1.4	Return on Rate Base - Working Cash	1,159	651	462	0	-	11	-	0	4	9	22	
1	Total Commodity Costs	898,780	504,343	359,108	139	-	8,714	-	84	2,932	6,736	16,725	
	VOLUMES (10^3 m^3)												
2.1	System and Buy/Sell Volumes	6,574,095	3,693,205	2,620,584	1,027	-	64,267	-	613	21,365	49,679	123,354	
2.2	System Volumes	6,574,095	3,693,205	2,620,584	1,027	-	64,267	-	613	21,365	49,679	123,354	
	GAS SUPPLY CHARGE SYSTEM (¢/m^3)												
3.1	Annual Commodity	13.5185	13.5185	13.5185	13.5185	-	13.5185	13.5185	13.5185	13.5185	13.5185	13.5185	1.1 / 2.1
3.2	Bad Debt Commodity	0.1130	0.0975	0.1448	-	-	-	-	0.0761	0.1663	-	-	1.2 / 2.1
3.3	System Gas Fee	0.0224	0.0224	0.0224	0.0224	-	0.0224	0.0224	0.0224	0.0224	0.0224	0.0224	1.3 / 2.2
3.4	Return on Rate Base - Working Cash	0.0176	0.0176	0.0176	0.0176	-	0.0176	0.0176	0.0176	0.0176	0.0176	0.0176	1.4 / 2.1
3	System Gas Supply Charge	13.6715	13.6560	13.7033	13.5585	-	13.5585	13.5585	13.6347	13.7248	13.5585	13.5585	
	GAS SUPPLY CHARGE BUY/SELL(¢/m3)												
4.1	Annual Commodity	13.5185	13.5185	13.5185	13.5185	-	13.5185	13.5185	13.5185	13.5185	13.5185	13.5185	1.1 / 2.1
4.2	Bad Debt Commodity	0.1130	0.0975	0.1448	-	-	-	-	0.0761	0.1663	-	-	1.2 / 2.1
4.3	Return on Rate Base - Working Cash	0.0176	0.0176	0.0176	0.0176	-	0.0176	0.0176	0.0176	0.0176	0.0176	0.0176	1.4 / 2.1
4	Buy/Sell Gas Supply Charge	13.6492	13.6336	13.6810	13.5361	-	13.5361	13.5361	13.6123	13.7025	13.5361	13.5361	

Witnesses: J. Collier
A. Kacicnik

CALCULATION OF GAS SUPPLY LOAD BALANCING & TRANSPORTATION CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF LOAD BALANCING CHARGES												
	ANNUAL LOAD BALANCING COSTS ($000)												
5.1	Peak	44,167	24,007	19,374	1	-	272	60	-	-	-	453	
5.2	Seasonal	3,421	1,573	1,646	(0)	-	39	21	-	33	62	47	
5.3	Return on Rate Base - Gas in Inventory	30,641	14,085	14,747	(1)	-	349	189	-	292	558	421	
5	Total Load Balancing	78,230	39,665	35,767	0	-	660	270	-	325	621	922	
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,268,896	4,583,338	4,772,169	1,177	-	488,031	532,453	55,183	154,354	519,974	162,216	
7	**ANNUAL LOAD BALANCING CHARGE (¢/m3)**		0.8654	0.7495	0.0037	-	0.1353	0.0507	-	0.2104	0.1194	0.5684	5.0 / 6
	DERIVATION OF TRANSPORTATION CHARGES												
8	Pipeline Annual incl. some M12 (upstream	442,874	227,622	191,613	58	-	9,101	569	1,233	2,409	3,254	7,014	
	VOLUMES (10^3 m^3)												
9	Total Transportation Volumes	7,788,644	4,003,100	3,369,817	1,027	-	160,062	10,015	21,679	42,372	57,218	123,354	
10	**PROPOSED TRANSPORTATION CHARGE (¢/m^3)**		5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	5.6862	

Witnesses: J. Collier
A. Kacicnik

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

RATE 135		
Seasonal Credits Applicable to Rate 135	**$**	**(465)**
Annual Volume (103 m3)		55,183
Mean Daily Volume (103 m3)		151
Annual Seasonal Credits	$	(3.08)
Payable from December to March	$	(0.77)
RATE 145		
Seasonal Credits Applicable to Rate 145	**$**	**(846)**
Annual Volume (103 m3)		154,354
Mean Daily Volume (103 m3)		
16 Hours		423
72 Hours		-
Annual Seasonal Credits		
16 Hours	$	(2.00)
Payable from December to March	$	(0.50)
72 Hours	$	(0.45)
Payable from December to March	$	(0.11)
Seasonal Credits Applicable to Rate 145		
16 Hours	$	(846)
72 Hours	$	-
RATE 170		
Seasonal Credits Applicable to Rate 170	**$**	**(6,268)**
Annual Volume (103 m3)		519,974
Mean Daily Volume (103 m3)		1,425
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)
RATE 200		
Seasonal Credits Applicable to Rate 200	**$**	**(196)**
Annual Volume (103 m3)		16,257
Mean Daily Volume (103 m3)		45
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³		Col. 2 EB-2011-0277 Bills & Volumes 10^3 m³	Col. 3 EB-2011-0277 Rate cents*	Col. 4 EB-2011-0277 Revenues $000
	RATE 1					
1.1	Customer Charge	Bills		21,921,543	$20.00	438,431
1.2	Delivery Charge	first	30	617,569	7.4497	46,007
1.3		next	55	860,715	6.9697	59,990
1.4		next	85	964,788	6.5937	63,615
1.5		over	170	2,140,266	6.3137	135,130
1.	Total Distribution Charge			4,583,338		743,173
2.1	Gas Supply Load Balancing			4,583,338	0.8654	39,665
2.2	Gas Supply Transportation			4,003,100	5.6862	227,622
3.1	Gas Supply Commodity - System			3,693,205	13.6560	504,344
3.2	Gas Supply Commodity - Buy/Sell			0	13.6336	0
3.	Total Gas Supply Charge			3,693,205		504,344
4.1	TOTAL DISTRIBUTION			4,583,338		743,173
4.2	TOTAL GAS SUPPLY LOAD BALANCING			4,583,338		267,287
4.3	TOTAL GAS SUPPLY COMMODITY			3,693,205		504,344
4.	TOTAL RATE 1			**4,583,338**		1,514,804
5.	Adj. Factor	0.9999				
6.	ADJUSTED REVENUE					**1,514,715**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m^3	Col. 2 EB-2011-0277 Bills & Volumes 10^3 m^3	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 6				
1.1	Customer Charge	Bills	1,889,984	$70.00	132,299
1.2	Delivery Charge	First 500	545,743	7.1109	38,807
1.3		Next 1050	656,613	5.4359	35,693
1.4		Next 4500	1,164,219	4.2633	49,634
1.5		Next 7000	695,918	3.5096	24,424
1.6		Next 15250	602,312	3.1747	19,122
1.7		Over 28300	1,107,364	3.0909	34,227
1.	Total Distribution Charge		4,772,169		334,205
2.1	Gas Supply Load Balancing		4,772,169	0.7495	35,767
2.2	Gas Supply Transportation		3,369,817	5.6862	191,613
3.1	Gas Supply Commodity - System		2,620,584	13.7033	359,106
3.2	Gas Supply Commodity - Buy/Sell		0	13.6810	0
3.	Total Gas Supply Charge		2,620,584		359,106
4.1	TOTAL DISTRIBUTION		4,772,169		334,205
4.2	TOTAL GAS SUPPLY LOAD BALANCING		4,772,169		227,380
4.3	TOTAL GAS SUPPLY COMMODITY		2,620,584		359,106
4.	TOTAL RATE 6		**4,772,169**		920,692
5.	Adj. Factor	1.000			
6.	ADJUSTED REVENUE				**920,638**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Rate Block m³ (Col. 1)	Bills & Volumes 10^3 m³ (Col. 2)	Rate cents* (Col. 3)	Revenues $000 (Col. 4)
			EB-2011-0277		
	RATE 9				
1.1	Customer Charge	Bills	108	$240.87	26
1.2	Delivery Charge	first 20000	966	10.8598	105
1.3		over 20000	211	10.1650	21
1.	Total Distribution Charge		1,177		152
2.1	Gas Supply Load Balancing		1,177	0.0037	0
2.2	Gas Supply Transportation		1,027	5.6862	58
3.1	Gas Supply Commodity - System		1,027	13.5585	139
3.2	Gas Supply Commodity - Buy/Sell		0	13.5361	0
3.	Total Gas Supply Charge		1,027		139
4.1	TOTAL DISTRIBUTION		1,177		152
4.2	TOTAL GAS SUPPLY LOAD BALANCING		1,177		58
4.3	TOTAL GAS SUPPLY COMMODITY		1,027		139
4	TOTAL RATE 9		**1,177**		**350**

Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
			EB-2011-0277		
	RATE 100				
1.1	Customer Charge	Contracts	0	$122.01	0
1.2	Demand Charge		0	8.19	0
1.3	Delivery Charge	first 14,000	0	5.1024	0
1.4		next 28,000	0	3.7434	0
1.5		over 42,000	0	3.1844	0
1	Total Distribution Charge		0		0
2.1	Gas Supply Load Balancing		0	0.4882	0
2.2	Gas Supply Transportation		0	5.6862	0
3.1	Gas Supply Commodity - System		0	13.5610	0
3.2	Gas Supply Commodity - Buy/Sell		0	13.5446	0
3	Total Gas Supply Charge		0		0
4.1	TOTAL DISTRIBUTION		0		0
4.2	TOTAL GAS SUPPLY LOAD BALANCING		0		0
4.3	TOTAL GAS SUPPLY COMMODITY		0		0
4	TOTAL RATE 100		**0**		**0**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m^3	Col. 2 EB-2011-0277 Contracts & Volumes $10^3 m^3$	Col. 3 EB-2011-0277 Rate cents*	Col. 4 EB-2011-0277 Revenues $000
	RATE 110				
1.1	Customer Charge	Contracts	2,436	$587.37	1,431
1.2	Demand Charge		28,041	22.9100	6,424
1.3	Delivery Charge	first 1,000,000	448,335	0.5810	2,605
1.4		over 1,000,000	39,696	0.4310	171
1.	Total Distribution Charge		488,031		10,631
2.1	Load Balancing Commodity		488,031	0.1353	660
2.2	Gas Supply Transportation		160,062	5.6862	9,101
2.	Total Gas Supply Load Balancing				9,761
3.1	Gas Supply Commodity - System		64,267	13.5585	8,714
3.2	Gas Supply Commodity - Buy/Sell		0	13.5361	0
3.	Total Gas Supply Charge		64,267		8,714
4.1	TOTAL DISTRIBUTION		488,031		10,631
4.2	TOTAL GAS SUPPLY LOAD BALANCING		488,031		9,761
4.3	TOTAL GAS SUPPLY COMMODITY		64,267		8,714
4.	TOTAL RATE 110		**488,031**		**29,106**

		Rate Block m^3	EB-2011-0277 Contracts & Volumes $10^3 m^3$	EB-2011-0277 Rate cents*	EB-2011-0277 Revenues $000
	RATE 115				
6.6	Customer Charge	Contracts	360	$622.62	224
6.2	Demand Charge		21,320	24.3600	5,193
6.3	Delivery Charge	first 1,000,000	155,980	0.2405	375
6.4		over 1,000,000	376,474	0.1405	529
6	Total Distribution Charge		532,453		6,322
7.1	Load Balancing Commodity		532,453	0.0507	270
7.2	Gas Supply Transportation		10,015	5.6862	569
7	Total Gas Supply Load Balancing				839
8.1	Gas Supply Commodity - System		0	13.5585	0
8.2	Gas Supply Commodity - Buy/Sell		0	13.5361	0
8.	Total Gas Supply Charge		0		0
9.1	TOTAL DISTRIBUTION		532,453		6,322
9.2	TOTAL GAS SUPPLY LOAD BALANCING		532,453		839
9.3	TOTAL GAS SUPPLY COMMODITY		0		0
9.	TOTAL RATE 115		**532,453**		**7,161**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2011-0277		
	RATE 125				
1.1	Customer Charge		56	$ 500.00	28
1.2	Demand Charge		106,168	9.1914	9,758
1.	Total Distribution Charge		106,168		9,786

Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
			EB-2011-0277		
	RATE 135				
	DEC to MAR				
1.1	Customer Charge	Contracts	152	$115.08	17
1.2	Delivery Charge	first 14,000	547	6.7507	37
1.3		next 28,000	865	5.5507	48
1.4		over 42,000	2,700	5.1507	139
1.	Total Distribution Charge		4,112		241
2.1	Gas Supply Load Balancing		4,112	0.0000	0
2.2	Gas Supply Transportation		1,536	5.6862	87
2.3	Seasonal Credit				(465)
3.1	Gas Supply Commodity - System		80	13.6347	11
3.2	Gas Supply Commodity - Buy/Sell		0	13.6123	0
3.	Total Gas Supply Charge		80		11
4.	SUB-TOTAL WINTER				-125
	APR to NOV				
5.1	Customer Charge	Contracts	304	$115.08	35
5.2	Delivery Charge	first 14,000	4,008	2.0507	82
5.3		next 28,000	7,758	1.3507	105
5.4		over 42,000	39,305	1.1507	452
5.	Total Distribution Charge		51,071		674
6.1	Gas Supply Load Balancing		51,071	0.0000	0
6.2	Gas Supply Transportation		20,143	5.6862	1,145
7.1	Gas Supply Commodity - System		533	13.6347	73
7.2	Gas Supply Commodity - Buy/Sell		0	13.6123	0
7.	Total Gas Supply Charge		533		73
8.	SUB-TOTAL SUMMER				1,892
9.1	TOTAL DISTRIBUTION		55,183		916
9.2	TOTAL GAS SUPPLY LOAD BALANCING		55,183		768
9.3	TOTAL GAS SUPPLY COMMODITY		613		84
9.	TOTAL RATE 135		**55,183**		**1,767**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Rate Block	Col. 1	Col. 2	Col. 3	Col. 4
				EB-2011-0277		
		Rate Block		Contracts & Volumes	Rate	Revenues
			m³	10^3 m³	cents*	$000
	RATE 145					
1.1	Customer Charge		Contracts	1,284	$123.34	158
1.2	Demand Charge			16,197	8.2300	1,333
1.2	Delivery Charge	first	14,000	16,769	2.8001	470
1.3		next	28,000	30,427	1.4411	438
1.4		over	42,000	107,157	0.8821	945
1.	Total Distribution Charge			154,354		3,345
2.1	Gas Supply Load Balancing			154,354	0.2104	325
2.2	Gas Supply Transportation			42,372	5.6862	2,409
2.3	Curtailment Credit					(846)
3.1	Gas Supply Commodity - System			21,365	13.7248	2,932
3.2	Gas Supply Commodity - Buy/Sell			0	13.7025	0
3.	Total Gas Supply Charge			21,365		2,932
4.1	TOTAL DISTRIBUTION			154,354		3,345
4.2	TOTAL GAS SUPPLY LOAD BALANCING			154,354		1,888
4.3	TOTAL GAS SUPPLY COMMODITY			21,365		2,932
4.	TOTAL RATE 145			**154,354**		**8,165**

				EB-2011-0277		
		Rate Block		Contracts & Volumes	Rate	Revenues
			m³	10^3 m³	cents*	$000
	RATE 170					
6.6	Customer Charge		Contracts	456	$280.16	128
6.2	Demand Charge			47,406	4.0900	1,939
6.3	Delivery Charge	first	1,000,000	325,530	0.5183	1,687
6.4		over	1,000,000	194,444	0.3183	619
6	Total Distribution Charge			519,974		4,373
7.1	Gas Supply Load Balancing			519,974	0.1194	621
7.7	Gas Supply Transportation			57,218	5.6862	3,254
7.3	Curtailment Credit					(6,268)
8.1	Gas Supply Commodity - System			49,679	13.5585	6,736
8.2	Gas Supply Commodity - Buy/Sell			0	13.5361	0
8.	Total Gas Supply Charge			49,679		6,736
9.1	TOTAL DISTRIBUTION			519,974		4,373
9.2	TOTAL GAS SUPPLY LOAD BALANCING			519,974		(2,394)
9.3	TOTAL GAS SUPPLY COMMODITY			49,679		6,736
9.	TOTAL RATE 170			**519,974**		**8,715**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

DETAILED REVENUE CALCULATION

Item No.		Rate Block	Contracts & Volumes	Rate	Revenues
		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2011-0277		
		m³	10³ m³	cents*	$000
	RATE 200				
1.1	Customer Charge	Contracts	12	$0.00	0
1.2	Demand Charge		13,622	14.7000	2,002
1.3	Delivery Charge		162,216	1.2519	2,031
1.	Total Distribution Charge		162,216		4,033
2.1	Gas Supply Load Balancing		162,216	0.5684	922
2.2	Gas Supply Transportation		123,354	5.6862	7,014
2.3	Curtailment Credit				(196)
3.1	Gas Supply Commodity - System		123,354	13.5585	16,725
3.2	Gas Supply Commodity - Buy/Sell		0	13.5361	0
3.	Total Gas Supply Charge		123,354		16,725
4.1	TOTAL DISTRIBUTION		162,216		4,033
4.2	TOTAL GAS SUPPLY LOAD BALANCING		162,216		7,740
4.3	TOTAL GAS SUPPLY COMMODITY		123,354		16,725
4.	TOTAL RATE 200		**162,216**		**28,498**

		Rate Block	Contracts & Volumes	Rate	Revenues
			EB-2011-0277		
		m³	10³ m³	cents*	$000
	RATE 300				
	Firm				
	Customer Charge		96	$500.00	48
	Demand Charge		887	25.2334	224
	Interruptible				
	Minimum Delivery Charge		31,049	0.3626	113
	Maximum Delivery Charge		0	0.9955	0
8.	TOTAL RATE 300		**0**		**384**

NOTE: * Cents unless otherwise noted.

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				**Heating, Water Htg. & Other Uses**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	240.00	228.00	12.00	5.3%	240.00	228.00	12.00	5.3%
1.3	DISTRIBUTION CHG.	$	203.44	200.03	3.41	1.7%	306.72	301.58	5.14	1.7%
1.4	LOAD BALANCING	§ $	200.73	204.50	(3.77)	-1.8%	307.35	313.10	(5.75)	-1.8%
1.5	SALES COMMDTY	$	418.43	419.43	(1.00)	-0.2%	640.61	642.15	(1.54)	-0.2%
1.6	TOTAL SALES	$	1,062.60	1,051.96	10.64	1.0%	1,494.68	1,484.83	9.85	0.7%
1.7	TOTAL T-SERVICE	$	644.17	632.53	11.64	1.8%	854.07	842.68	11.39	1.4%
1.8	SALES UNIT RATE	$/m³	0.3468	0.3433	0.0035	1.0%	0.3186	0.3165	0.0021	0.7%
1.9	T-SERVICE UNIT RATE	$/m³	0.2102	0.2064	0.0038	1.8%	0.1821	0.1796	0.0024	1.4%
1.10	SALES UNIT RATE	$/GJ	9.201	9.109	0.0921	1.0%	8.454	8.398	0.0557	0.7%
1.11	T-SERVICE UNIT RATE	$/GJ	5.578	5.477	0.1008	1.8%	4.831	4.766	0.0644	1.4%

			Heating Only				**Heating & Water Htg.**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	240.00	228.00	12.00	5.3%	240.00	228.00	12.00	5.3%
2.3	DISTRIBUTION CHG.	$	130.45	128.30	2.15	1.7%	135.77	133.50	2.27	1.7%
2.4	LOAD BALANCING	§ $	128.07	130.50	(2.43)	-1.9%	131.36	133.82	(2.46)	-1.8%
2.5	SALES COMMDTY	$	266.98	267.61	(0.63)	-0.2%	273.80	274.46	(0.66)	-0.2%
2.6	TOTAL SALES	$	765.50	754.41	11.09	1.5%	780.93	769.78	11.15	1.4%
2.7	TOTAL T-SERVICE	$	498.52	486.80	11.72	2.4%	507.13	495.32	11.81	2.4%
2.8	SALES UNIT RATE	$/m³	0.3916	0.3859	0.0057	1.5%	0.3895	0.3839	0.0056	1.4%
2.9	T-SERVICE UNIT RATE	$/m³	0.2550	0.2490	0.0060	2.4%	0.2529	0.2470	0.0059	2.4%
2.10	SALES UNIT RATE	$/GJ	10.389	10.238	0.1505	1.5%	10.334	10.187	0.1475	1.4%
2.11	T-SERVICE UNIT RATE	$/GJ	6.766	6.607	0.1591	2.4%	6.711	6.555	0.1563	2.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	240.00	228.00	12.00	5.3%	240.00	228.00	12.00	5.3%
3.3	DISTRIBUTION CHG.	$	329.84	324.33	5.51	1.7%	76.65	75.35	1.30	1.7%
3.4	LOAD BALANCING	§ $	330.71	336.93	(6.22)	-1.8%	70.82	72.14	(1.32)	-1.8%
3.5	SALES COMMDTY	$	689.37	691.02	(1.65)	-0.2%	147.63	147.98	(0.35)	-0.2%
3.6	TOTAL SALES	$	1,589.92	1,580.28	9.64	0.6%	535.10	523.47	11.63	2.2%
3.7	TOTAL T-SERVICE	$	900.55	889.26	11.29	1.3%	387.47	375.49	11.98	3.2%
3.8	SALES UNIT RATE	$/m³	0.3150	0.3131	0.0019	0.6%	0.4950	0.4842	0.0108	2.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.1784	0.1762	0.0022	1.3%	0.3584	0.3474	0.0111	3.2%
3.10	SALES UNIT RATE	$/GJ	8.357	8.306	0.0507	0.6%	13.134	12.848	0.2854	2.2%
3.11	T-SERVICE UNIT RATE	$/GJ	4.733	4.674	0.0593	1.3%	9.510	9.216	0.2940	3.2%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				Com. Htg., Air Cond'ng & Other Uses			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	840.00	780.00	60.00	7.7%	840.00	780.00	60.00	7.7%
1.3	DISTRIBUTION CHG.	$	1,216.50	1,196.53	19.97	1.7%	1,560.84	1,535.19	25.65	1.7%
1.4	LOAD BALANCING	§ $	1,454.84	1,486.47	(31.63)	-2.1%	1,884.23	1,925.18	(40.95)	-2.1%
1.5	SALES COMMDTY	$	3,097.76	3,109.15	(11.39)	-0.4%	4,012.03	4,026.82	(14.79)	-0.4%
1.6	TOTAL SALES	$	6,609.10	6,572.15	36.95	0.6%	8,297.10	8,267.19	29.91	0.4%
1.7	TOTAL T-SERVICE	$	3,511.34	3,463.00	48.34	1.4%	4,285.07	4,240.37	44.70	1.1%
1.8	SALES UNIT RATE	$/m³	0.2924	0.2907	0.0016	0.6%	0.2834	0.2824	0.0010	0.4%
1.9	T-SERVICE UNIT RATE	$/m³	0.1553	0.1532	0.0021	1.4%	0.1464	0.1448	0.0015	1.1%
1.10	SALES UNIT RATE	$/GJ	7.757	7.714	0.0434	0.6%	7.519	7.492	0.0271	0.4%
1.11	T-SERVICE UNIT RATE	$/GJ	4.121	4.064	0.0567	1.4%	3.883	3.843	0.0405	1.1%

Item No.			Medium Commercial Customer				Large Commercial Customer			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	840.00	780.00	60.00	7.7%	840.00	780.00	60.00	7.7%
2.3	DISTRIBUTION CHG.	$	6,551.21	6,443.39	107.82	1.7%	11,994.94	11,797.49	197.45	1.7%
2.4	LOAD BALANCING	§ $	10,912.47	11,149.65	(237.18)	-2.1%	21,824.87	22,299.21	(474.34)	-2.1%
2.5	SALES COMMDTY	$	23,235.73	23,321.19	(85.46)	-0.4%	46,471.30	46,642.23	(170.93)	-0.4%
2.6	TOTAL SALES	$	41,539.41	41,694.23	(154.82)	-0.4%	81,131.11	81,518.93	(387.82)	-0.5%
2.7	TOTAL T-SERVICE	$	18,303.68	18,373.04	(69.36)	-0.4%	34,659.81	34,876.70	(216.89)	-0.6%
2.8	SALES UNIT RATE	$/m³	0.2450	0.2459	(0.0009)	-0.4%	0.2392	0.2404	(0.0011)	-0.5%
2.9	T-SERVICE UNIT RATE	$/m³	0.1079	0.1084	(0.0004)	-0.4%	0.1022	0.1028	(0.0006)	-0.6%
2.10	SALES UNIT RATE	$/GJ	6.500	6.524	(0.0242)	-0.4%	6.347	6.378	(0.0303)	-0.5%
2.11	T-SERVICE UNIT RATE	$/GJ	2.864	2.875	(0.0109)	-0.4%	2.712	2.729	(0.0170)	-0.6%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	840.00	780.00	60.00	7.7%	840.00	780.00	60.00	7.7%
3.3	DISTRIBUTION CHG.	$	2,156.71	2,121.28	35.43	1.7%	2,892.58	2,845.01	47.57	1.7%
3.4	LOAD BALANCING	§ $	2,785.66	2,846.21	(60.55)	-2.1%	4,112.57	4,201.96	(89.39)	-2.1%
3.5	SALES COMMDTY	$	5,931.47	5,953.30	(21.83)	-0.4%	8,756.83	8,789.05	(32.22)	-0.4%
3.6	TOTAL SALES	$	11,713.84	11,700.79	13.05	0.1%	16,601.98	16,616.02	(14.04)	-0.1%
3.7	TOTAL T-SERVICE	$	5,782.37	5,747.49	34.88	0.6%	7,845.15	7,826.97	18.18	0.2%
3.8	SALES UNIT RATE	$/m³	0.2706	0.2703	0.0003	0.1%	0.2598	0.2600	(0.0002)	-0.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1336	0.1328	0.0008	0.6%	0.1228	0.1225	0.0003	0.2%
3.10	SALES UNIT RATE	$/GJ	7.180	7.172	0.0080	0.1%	6.893	6.899	(0.0058)	-0.1%
3.11	T-SERVICE UNIT RATE	$/GJ	3.544	3.523	0.0214	0.6%	3.257	3.250	0.0075	0.2%

			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	840.00	780.00	60.00	7.7%	840.00	780.00	60.00	7.7%
4.3	DISTRIBUTION CHG.	$	6,708.78	6,598.40	110.38	1.7%	12,112.01	11,912.69	199.32	1.7%
4.4	LOAD BALANCING	§ $	10,912.48	11,149.64	(237.16)	-2.1%	21,824.84	22,299.12	(474.28)	-2.1%
4.5	SALES COMMDTY	$	23,235.73	23,321.18	(85.45)	-0.4%	46,471.16	46,642.10	(170.94)	-0.4%
4.6	TOTAL SALES	$	41,696.99	41,849.22	(152.23)	-0.4%	81,248.01	81,633.91	(385.90)	-0.5%
4.7	TOTAL T-SERVICE	$	18,461.26	18,528.04	(66.78)	-0.4%	34,776.85	34,991.81	(214.96)	-0.6%
4.8	SALES UNIT RATE	$/m³	0.2459	0.2468	(0.0009)	-0.4%	0.2396	0.2407	(0.0011)	-0.5%
4.9	T-SERVICE UNIT RATE	$/m³	0.1089	0.1093	(0.0004)	-0.4%	0.1025	0.1032	(0.0006)	-0.6%
4.10	SALES UNIT RATE	$/GJ	6.525	6.548	(0.0238)	-0.4%	6.357	6.387	(0.0302)	-0.5%
4.11	T-SERVICE UNIT RATE	$/GJ	2.889	2.899	(0.0104)	-0.4%	2.721	2.738	(0.0168)	-0.6%

§ The Load Balancing Charge shown here includes proposed transportation charges

Witnesses: J. Collier
A. Kacicnik

ANNUAL BIL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
1.2	CUSTOMER CHG.	$	1,464.12	1,464.12	0.00	0.0%	1,464.12	1,464.12	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	17,558.79	17,625.93	(67.14)	-0.4%	27,928.72	28,047.19	(118.47)	-0.4%
1.4	LOAD BALANCING	$	20,942.83	21,399.04	(456.22)	-2.1%	36,957.97	37,763.08	(805.10)	-2.1%
1.5	SALES COMMDTY	$	45,997.40	46,166.59	(169.19)	-0.4%	81,172.00	81,470.56	(298.56)	-0.4%
1.6	TOTAL SALES	$	85,963.14	86,655.68	(692.55)	-0.8%	147,522.81	148,744.95	(1,222.13)	-0.8%
1.7	TOTAL T-SERVICE	$	39,965.74	40,489.09	(523.36)	-1.3%	66,350.81	67,274.39	(923.57)	-1.4%
1.8	SALES UNIT RATE	$/m³	0.2534	0.2555	(0.0020)	-0.8%	0.2465	0.2485	(0.0020)	-0.8%
1.9	T-SERVICE UNIT RATE	$/m³	0.1178	0.1194	(0.0015)	-1.3%	0.1108	0.1124	(0.0015)	-1.4%
1.10	SALES UNIT RATE	$/GJ	6.724	6.778	(0.0542)	-0.8%	6.539	6.593	(0.0542)	-0.8%
1.11	T-SERVICE UNIT RATE	$/GJ	3.126	3.167	(0.0409)	-1.3%	2.941	2.982	(0.0409)	-1.4%

			Rate 100 - Small Industrial Firm				**Rate 100 - Average Industrial Firm**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
2.2	CUSTOMER CHG.	$	1,464.12	1,464.12	0.00	0.0%	1,464.12	1,464.12	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	17,831.59	17,898.72	(67.13)	-0.4%	28,170.13	28,288.59	(118.46)	-0.4%
2.4	LOAD BALANCING	$	20,942.82	21,399.04	(456.22)	-2.1%	36,957.92	37,763.01	(805.09)	-2.1%
2.5	SALES COMMDTY	$	45,997.39	46,166.56	(169.17)	-0.4%	81,171.87	81,470.41	(298.54)	-0.4%
2.6	TOTAL SALES	$	86,235.92	86,928.44	(692.52)	-0.8%	147,764.04	148,986.13	(1,222.09)	-0.8%
2.7	TOTAL T-SERVICE	$	40,238.53	40,761.88	(523.35)	-1.3%	66,592.17	67,515.72	(923.55)	-1.4%
2.8	SALES UNIT RATE	$/m³	0.2542	0.2563	(0.0020)	-0.8%	0.2469	0.2489	(0.0020)	-0.8%
2.9	T-SERVICE UNIT RATE	$/m³	0.1186	0.1202	(0.0015)	-1.3%	0.1113	0.1128	(0.0015)	-1.4%
2.10	SALES UNIT RATE	$/GJ	6.746	6.800	(0.0542)	-0.8%	6.550	6.604	(0.0542)	-0.8%
2.11	T-SERVICE UNIT RATE	$/GJ	3.148	3.189	(0.0409)	-1.3%	2.952	2.993	(0.0409)	-1.4%

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				**Rate 145 - Average Commercial Interr.**			
			(A)	**(B)**	**CHANGE** (A) - (B)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,480.08	1,480.08	0.00	0.0%	1,480.08	1,480.08	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	9,764.23	9,781.18	(16.95)	-0.2%	14,169.85	14,199.74	(29.89)	-0.2%
3.4	LOAD BALANCING	$	18,139.87	18,740.95	(601.08)	-3.2%	32,011.96	33,072.71	(1,060.75)	-3.2%
3.5	SALES COMMDTY	$	46,552.87	46,617.32	(64.45)	-0.1%	82,152.25	82,265.99	(113.74)	-0.1%
3.6	TOTAL SALES	$	75,937.05	76,619.53	(682.48)	-0.9%	129,814.14	131,018.52	(1,204.38)	-0.9%
3.7	TOTAL T-SERVICE	$	29,384.18	30,002.21	(618.03)	-2.1%	47,661.89	48,752.53	(1,090.64)	-2.2%
3.8	SALES UNIT RATE	$/m³	0.2239	0.2259	(0.0020)	-0.9%	0.2169	0.2189	(0.0020)	-0.9%
3.9	T-SERVICE UNIT RATE	$/m³	0.0866	0.0885	(0.0018)	-2.1%	0.0796	0.0814	(0.0018)	-2.2%
3.10	SALES UNIT RATE	$/GJ	5.940	5.993	(0.0534)	-0.9%	5.754	5.808	(0.0534)	-0.9%
3.11	T-SERVICE UNIT RATE	$/GJ	2.299	2.347	(0.0483)	-2.1%	2.113	2.161	(0.0483)	-2.2%

Item No.			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)	%	**(A)**	**(B)**	**CHANGE** (A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,480.08	1,480.08	0.00	0.0%	1,480.08	1,480.08	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	10,037.02	10,053.97	(16.95)	-0.2%	14,411.30	14,441.21	(29.91)	-0.2%
4.4	LOAD BALANCING	$	18,139.88	18,740.94	(601.06)	-3.2%	32,011.89	33,072.64	(1,060.75)	-3.2%
4.5	SALES COMMDTY	$	46,552.87	46,617.33	(64.46)	-0.1%	82,152.12	82,265.84	(113.72)	-0.1%
4.6	TOTAL SALES	$	76,209.85	76,892.32	(682.47)	-0.9%	130,055.39	131,259.77	(1,204.38)	-0.9%
4.7	TOTAL T-SERVICE	$	29,656.98	30,274.99	(618.01)	-2.0%	47,903.27	48,993.93	(1,090.66)	-2.2%
4.8	SALES UNIT RATE	$/m³	0.2247	0.2267	(0.0020)	-0.9%	0.2173	0.2193	(0.0020)	-0.9%
4.9	T-SERVICE UNIT RATE	$/m³	0.0874	0.0893	(0.0018)	-2.0%	0.0800	0.0819	(0.0018)	-2.2%
4.10	SALES UNIT RATE	$/GJ	5.961	6.015	(0.0534)	-0.9%	5.765	5.818	(0.0534)	-0.9%
4.11	T-SERVICE UNIT RATE	$/GJ	2.320	2.368	(0.0483)	-2.0%	2.123	2.172	(0.0483)	-2.2%

Witnesses: J. Collier
A. Kacicnik

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				Rate 110 - Average Ind. Firm - 50% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,048.44	7,048.44	0.00	0.0%	7,048.44	7,048.44	0.00	0.0%
5.3	DISTRIBUTION CHG.	$	12,528.31	12,609.17	(80.86)	-0.6%	205,029.80	206,377.37	(1,347.57)	-0.7%
5.4	LOAD BALANCING	$	34,845.14	35,206.42	(361.28)	-1.0%	580,751.62	586,773.09	(6,021.47)	-1.0%
5.5	SALES COMMDTY	$	81,156.85	81,277.13	(120.28)	-0.1%	1,352,612.37	1,354,617.56	(2,005.19)	-0.1%
5.6	TOTAL SALES	$	135,578.74	136,141.16	(562.42)	-0.4%	2,145,442.23	2,154,816.46	(9,374.23)	-0.4%
5.7	TOTAL T-SERVICE	$	54,421.89	54,864.03	(442.14)	-0.8%	792,829.86	800,198.90	(7,369.04)	-0.9%
5.8	SALES UNIT RATE	$/m³	0.2265	0.2274	(0.0009)	-0.4%	0.2151	0.2160	(0.0009)	-0.4%
5.9	T-SERVICE UNIT RATE	$/m³	0.0909	0.0917	(0.0007)	-0.8%	0.0795	0.0802	(0.0007)	-0.9%
5.10	SALES UNIT RATE	$/GJ	6.010	6.035	(0.0249)	-0.4%	5.706	5.731	(0.0249)	-0.4%
5.11	T-SERVICE UNIT RATE	$/GJ	2.412	2.432	(0.0196)	-0.8%	2.109	2.128	(0.0196)	-0.9%
			Rate 110 - Average Ind. Firm - 75% LF				Rate 115 - Large Ind. Firm - 80% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,048.44	7,048.44	0.00	0.0%	7,471.44	7,471.44	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	158,071.87	159,419.45	(1,347.58)	-0.8%	808,550.51	866,082.92	(57,532.41)	-6.6%
6.4	LOAD BALANCING	$	580,751.58	586,772.99	(6,021.41)	-1.0%	4,006,216.49	4,031,204.14	(24,987.65)	-0.6%
6.5	SALES COMMDTY	$	1,352,612.23	1,354,617.41	(2,005.18)	-0.1%	9,468,286.97	9,482,323.37	(14,036.40)	-0.1%
6.6	TOTAL SALES	$	2,098,484.12	2,107,858.29	(9,374.17)	-0.4%	14,290,525.41	14,387,081.87	(96,556.46)	-0.7%
6.7	TOTAL T-SERVICE	$	745,871.89	753,240.88	(7,368.99)	-1.0%	4,822,238.44	4,904,758.50	(82,520.06)	-1.7%
6.8	SALES UNIT RATE	$/m³	0.2104	0.2113	(0.0009)	-0.4%	0.2046	0.2060	(0.0014)	-0.7%
6.9	T-SERVICE UNIT RATE	$/m³	0.0748	0.0755	(0.0007)	-1.0%	0.0691	0.0702	(0.0012)	-1.7%
6.10	SALES UNIT RATE	$/GJ	5.581	5.606	(0.0249)	-0.4%	5.430	5.466	(0.0367)	-0.7%
6.11	T-SERVICE UNIT RATE	$/GJ	1.984	2.003	(0.0196)	-1.0%	1.832	1.864	(0.0314)	-1.7%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2011-0277 @ 37.69 MJ/m³ vs (B) EB-2011-0296 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				Rate 170 - Average Ind. Interr. - 50% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,380.96	1,380.96	0.00	0.0%	3,361.92	3,351.72	10.20	0.3%
7.3	DISTRIBUTION CHG.	$	8,312.3	8,369.88	(57.61)	-0.7%	76,760.6	76,608.49	152.12	0.2%
7.4	LOAD BALANCING	$	28,989.96	29,181.15	(191.19)	-0.7%	458,907.46	469,916.98	(11,009.52)	-2.3%
7.5	SALES COMMDTY	$	81,612.82	81,760.67	(147.85)	-0.2%	1,352,612.37	1,354,617.56	(2,005.19)	-0.1%
7.6	TOTAL SALES	$	120,296.01	120,692.66	(396.65)	-0.3%	1,891,642.36	1,904,494.75	(12,852.39)	-0.7%
7.7	TOTAL T-SERVICE	$	38,683.19	38,931.99	(248.80)	-0.6%	539,029.99	549,877.19	(10,847.20)	-2.0%
7.8	SALES UNIT RATE	$/m³	0.2010	0.2016	(0.0007)	-0.3%	0.1896	0.1909	(0.0013)	-0.7%
7.9	T-SERVICE UNIT RATE	$/m³	0.0646	0.0650	(0.0004)	-0.6%	0.0540	0.0551	(0.0011)	-2.0%
7.10	SALES UNIT RATE	$/GJ	5.332	5.350	(0.0176)	-0.3%	5.031	5.065	(0.0342)	-0.7%
7.11	T-SERVICE UNIT RATE	$/GJ	1.715	1.726	(0.0110)	-0.6%	1.434	1.462	(0.0288)	-2.0%
			Rate 170 - Average Ind. Interr. - 75% LF				Rate 170 - Large Ind. Interr. - 75% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,361.92	3,351.72	10.20	0.3%	3,361.92	3,351.72	10.20	0.3%
8.3	DISTRIBUTION CHG.	$	69,575.8	69,423.66	152.13	0.2%	371,462.2	370,397.36	1,064.81	0.3%
8.4	LOAD BALANCING	$	458,907.40	469,916.95	(11,009.55)	-2.3%	3,212,352.42	3,289,419.13	(77,066.71)	-2.3%
8.5	SALES COMMDTY	$	1,352,612.23	1,354,617.41	(2,005.18)	-0.1%	9,468,286.97	9,482,323.37	(14,036.40)	-0.1%
8.6	TOTAL SALES	$	1,884,457.34	1,897,309.74	(12,852.40)	-0.7%	13,055,463.48	13,145,491.58	(90,028.10)	-0.7%
8.7	TOTAL T-SERVICE	$	531,845.11	542,692.33	(10,847.22)	-2.0%	3,587,176.51	3,663,168.21	(75,991.70)	-2.1%
8.8	SALES UNIT RATE	$/m³	0.1889	0.1902	(0.0013)	-0.7%	0.1870	0.1882	(0.0013)	-0.7%
8.9	T-SERVICE UNIT RATE	$/m³	0.0533	0.0544	(0.0011)	-2.0%	0.0514	0.0525	(0.0011)	-2.1%
8.10	SALES UNIT RATE	$/GJ	5.012	5.046	(0.0342)	-0.7%	4.960	4.994	(0.0342)	-0.7%
8.11	T-SERVICE UNIT RATE	$/GJ	1.414	1.443	(0.0288)	-2.0%	1.363	1.392	(0.0289)	-2.1%

Witnesses: J. Collier
A. Kacicnik

Measure of 2012 Revenues vs 2012 Revenue Requirement
December 31, 2012

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col.10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Sales and Delivery Revenue	2,533.12	1,514.72	920.64	0.35	0.00	29.11	7.16	9.79	1.77	8.17	8.71	28.50	0.38	1.62	2.22
2.	Unbilled Revenues	7.26	1.76	5.02	0.00	0.00	0.22	0.02	0.00	0.00	0.16	0.08	0.00	0.00	0.00	0.00
3.	Total Revenues	2,540.39	1,516.48	925.66	0.35	0.00	29.32	7.18	9.79	1.77	8.33	8.80	28.50	0.38	1.62	2.22
4.	Proposed 2012 Revenue Requirement	2,540.39	1,516.27	924.50	0.46	0.00	29.83	6.53	10.03	1.95	8.81	9.15	28.54	0.47	1.62	2.22
5.	Measure of Revenues vs Revenue Requirement	1.00	1.00	1.00	0.76	0.00	0.98	1.10	0.98	0.90	0.95	0.96	1.00	0.82	1.00	1.00

Measure of 2012 Revenues vs 2012 Revenue Requirement
Excluding Gas Supply Commodity
December 31, 2012

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col.10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Sales and Delivery Revenue	1,634.34	1,010.37	561.53	0.21	0.00	20.39	7.16	9.79	1.68	5.23	1.98	11.77	0.38	1.62	2.22
2.	Unbilled Revenues	7.26	1.76	5.02	0.00	0.00	0.22	0.02	0.00	0.00	0.16	0.08	0.00	0.00	0.00	0.00
3.	Total Revenues	1,641.61	1,012.13	566.55	0.21	0.00	20.61	7.18	9.79	1.69	5.40	2.06	11.77	0.38	1.62	2.22
4.	Proposed 2012 Revenue Requirement	1,641.61	1,011.93	565.39	0.32	0.00	21.11	6.53	10.03	1.87	5.87	2.42	11.82	0.47	1.62	2.22
5.	Measure of Revenues vs Revenue Requirement excluding Gas Supply Commodity	1.00	1.00	1.00	0.66	0.00	0.98	1.10	0.98	0.90	0.92	0.85	1.00	0.82	1.00	1.00

Total 2012 Revenue Requirement
December 31, 2012
(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE	Reference
1	PRODUCT COSTS	898.8	504.3	359.1	0.1	-	8.7	-	-	0.1	2.9	6.7	16.7	-	-	-	Ex.B/T3/S10/P4/L1 & Ex.B/T3/S10/P5/L1
2	PIPELINE TRANS. AND LOAD BALANCING	513.8	267.7	227.4	0.1	-	9.7	0.7	-	1.2	1.9	(2.5)	7.7	-	-	-	Ex.B/T3/S10/P4/L2 & Ex.B/T3/S10/P5/L2
3	STORAGE	156.4	79.3	71.6	(0.0)	-	1.3	0.7	-	(0.5)	0.7	1.3	1.9	-	-	-	Ex.B/T3/S10/P4/L3 & Ex.B/T3/S10/P5/L3
4	DISTRIBUTION	501.5	289.7	181.9	0.0	0.0	8.4	4.5	9.5	0.3	2.6	2.7	1.5	0.3	0.1	-	Ex.B/T3/S10/P4/L4 & Ex.B/T3/S10/P5/L4
5	CUSTOMER RELATED	468.3	375.2	84.4	0.2	0.0	1.9	0.7	0.5	0.8	0.7	0.9	0.7	0.1	0.0	2.2	Ex.B/T3/S10/P5/L5
Total 2012 Revenue Requirement		2,538.8	1,516.2	924.4	0.5	0.0	30.0	6.5	10.0	2.0	8.8	9.2	28.5	0.3	0.2	2.2	

2012 Gas Cost to Operations Revenue Requirement

December 31, 2012

(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE	Allocation
	SUPPLY COSTS																
	PRODUCT COSTS																
1.1	Annual Commodity	888.7	499.2	354.2	0.1	-	8.7	-	-	0.1	2.9	6.7	16.7	-	-	-	1.1
1	Total Gas Cost	888.7	499.2	354.2	0.1	-	8.7	-	-	0.1	2.9	6.7	16.7	-	-	-	-
	PIPELINE TRANS. AND LOAD BALANCING																
2.1	Peak	44.2	24.1	19.1	-	-	0.4	0.1	-	-	-	-	0.5	-	-	-	3.1
2.2	Seasonal	2.3	1.1	1.1	(0.0)	-	0.0	0.0	-	-	0.0	0.0	0.0	-	-	-	3.2
2.3	Annual - Transportation	446.6	229.5	193.2	0.1	-	9.2	0.6	-	1.2	2.4	3.3	7.1	-	-	-	1.4
2.4	Seasonal Credit	(7.3)	-	-	-	-	-	-	-	-	(0.8)	(6.3)	(0.2)	-	-	-	-
2	Total Pipeline Trans. Cost	485.8	254.8	213.5	0.1	-	9.6	0.7	-	1.2	1.6	(2.9)	7.4	-	-	-	-
	STORAGE																
3.1	Deliverability	63.0	34.4	27.3	-	-	0.5	0.2	-	-	-	-	0.6	-	-	-	3.1
3.2	Space	58.3	26.8	28.1	(0.0)	-	0.7	0.4	-	-	0.6	1.1	0.8	-	-	-	3.2
3.3	Seasonal Credit	(0.5)	-	-	-	-	-	-	-	(0.5)	-	-	-	-	-	-	-
3	Total Storage	120.9	61.2	55.3	(0.0)	-	1.2	0.5	-	(0.5)	0.6	1.1	1.4	-	-	-	-
	DISTRIBUTION																
4.1	Commodity	19.9	8.1	8.4	0.0	-	0.9	0.9	-	0.1	0.3	0.9	0.3	-	-	-	1.2
4	Total Distribution	19.9	8.1	8.4	0.0	-	0.9	0.9	-	0.1	0.3	0.9	0.3	-	-	-	-
	Total 2012 Gas Cost to Operations Revenue Requirement	1,515.3	823.3	631.5	0.2	-	20.3	2.2	-	1.0	5.3	5.8	25.8	-	-	-	-

2012 Distribution Revenue Requirement
December 31, 2012
(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	SUPPLY RELATED															
1	PRODUCT RELATED	10.1	5.1	4.9	0.0	-	0.0	-	-	0.0	0.0	0.0	0.1	-	-	-
2	LOAD BALANCING RELATED	28.0	12.9	14.0	(0.0)	-	0.1	(0.0)	-	(0.0)	0.3	0.4	0.4	-	-	-
	FACILITIES' COSTS															
3	STORAGE	35.5	18.0	16.3	(0.0)	-	0.1	0.1	-	-	0.2	0.3	0.4	-	-	-
4	DISTRIBUTION	481.6	281.6	173.4	0.0	0.0	7.5	3.5	9.5	0.2	2.3	1.8	1.3	0.3	0.1	-
5	CUSTOMER RELATED	468.3	375.2	84.4	0.2	0.0	1.9	0.7	0.5	0.8	0.7	0.9	0.7	0.1	0.0	2.2
Total 2012 Distribution Revenue Requirement		1,023.5	692.8	292.9	0.3	0.0	9.7	4.4	10.0	1.0	3.5	3.4	2.8	0.3	0.2	2.2

2012 Y- and Z- Factor Revenue Requirement
December 31, 2012
(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE	Assignment
	Y Factor: Other																
1.1	2012 Gas in Storage and Working Cash Carrying Cost	30.6	14.1	14.7	(0.0)	0.0	0.3	0.2	0.0	0.0	0.3	0.6	0.4	0.0	0.0		3.2
1.2	2012 DSM Program Costs*	23.8	7.4	13.3	0.0	0.0	1.2	0.3	0.0	0.1	0.7	0.7	0.0	0.0	0.0		Direct
1.3	2012 DSM Low Income*	4.3	2.9	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		EB-2010-0146 ExB T3 S10 p5
1.4	2012 CIS/ Customer Care	99.2	91.3	7.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		4.1
		157.9	115.7	37.1	0.0	0.0	1.6	0.5	0.0	0.1	1.0	1.3	0.4	0.0	0.0		
	Y Factor: Capital Investment																
1.5	2012 Leave to Construct	6.6	3.0	2.7	0.0	0.0	0.1	0.1	0.6	0.0	0.0	0.0	0.1	0.0	0.0		2.1
		6.6	3.0	2.7	0.0	0.0	0.1	0.1	0.6	0.0	0.0	0.0	0.1	0.0	0.0		
1.6	**Total Y-Factor: Other & Capital Investment**	164.5	118.7	39.8	0.0	0.0	1.7	0.6	0.6	0.1	1.1	1.3	0.5	0.0	0.0		
	Z Factor: Proposed																
1.7	2012 Pension Funding requirement	16.6	11.2	4.8	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	0.0	ExB T3 S10 p7
1.8	2012 Crossbore/Sewer Lateral Program requirement	3.8	3.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.2
1.9	Total Z-Factor (Proposed)	20.4	14.7	5.1	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	0.0	
2.0	**Total All Y- & Z-Factors**	184.9	133.4	44.9	0.0	0.0	1.9	0.7	0.8	0.1	1.1	1.4	0.6	0.0	0.0	0.0	
	* Note: 2012 Total DSM Y-factor amount (1.2 + 1.3)	28.1	10.4	14.5	0.0	0.0	1.3	0.3	0.0	0.1	0.7	0.8	0.0	0.0	0.0	0.0	

2012 Distribution Revenue Requirement with Y- and Z- Factor Detail
December 31, 2012
(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300 Firm	Col. 14 RATE 300 Int	Col. 15 DIRECT PURCHASE	Col. 16
1.0	DRR before Y- & Z- Factors	838.6	559.4	248.0	0.3	0.0	7.8	3.7	9.3	0.9	2.4	2.0	2.2	0.3	0.2	2.2	
	Y Factor: Other																
1.1	2012 Gas in Storage and Working Cash Carrying Cost	30.6	14.1	14.7	(0.0)	-	0.3	0.2	0.0	0.0	0.3	0.6	0.4	0.0	-	-	
1.2	2012 DSM Program Costs*	23.8	7.4	13.3	-	-	1.2	0.3	0.0	0.1	0.7	0.7	0.0	0.0	-	-	
1.3	2012 DSM Low Income*	4.3	2.9	1.2	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	
1.4	2012 CIS/ Customer Care	99.2	91.3	7.9	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	
	Y Factor: Capital Investment																
1.5	2012 Leave to Construct	6.6	3.0	2.7	0.0	-	0.1	0.1	0.6	0.0	0.0	0.0	0.1	0.0	-	-	
1.6	**Total Y-Factor**	164.5	118.7	39.8	0.0	-	1.7	0.6	0.6	0.1	1.1	1.3	0.5	0.0	0.0	-	
1.7	**DRR with Y-Factors**	1,003.1	678.2	287.8	0.3	0.0	9.5	4.3	9.9	1.0	3.4	3.3	2.7	0.3	0.2	2.2	
	Z Factor: Proposed																allocated in proportion
1.8	2012 Pension Funding requirement	16.6	11.2	4.8	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	-	to Line 1.7
1.9	2012 Crossbore/Sewer Lateral Program requirement	3.8	3.4	0.4	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	
2.0	Total Z-Factor (Proposed)	20.4	14.7	5.1	0.0	0.0	0.2	0.1	0.2	0.0	0.1	0.1	0.0	0.0	0.0	-	
2.1	**Total 2012 DRR with All Y-& Z-Factors**	1,023.5	692.8	292.9	0.3	0.0	9.7	4.4	10.0	1.0	3.5	3.4	2.8	0.3	0.2	2.2	
	* Note:																
	2012 Total DSM Y-factor amount (1.2 + 1.3)	28.1	10.4	14.5	0.0	0.0	1.3	0.3	0.0	0.1	0.7	0.8	0.0	0.0	0.0	0.0	

Allocators
December 31, 2012

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
	FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	6,574.1	3,693.2	2,620.6	1.0	0.0	64.3	0.0	0.0	0.6	21.4	49.7	123.4	0.0	0.0	0.0
1.2 Bundled Annual Deliveries	11,268.9	4,583.3	4,772.2	1.2	0.0	488.0	532.5	0.0	55.2	154.4	520.0	162.2	0.0	0.0	0.0
1.3 Total Annual Deliveries	11,299.9	4,583.3	4,772.2	1.2	0.0	488.0	532.5	0.0	55.2	154.4	520.0	162.2	0.0	31.0	0.0
1.4 Bundled Transportation Deliveries	7,788.6	4,003.1	3,369.8	1.0	0.0	160.1	10.0	0.0	21.7	42.4	57.2	123.3	0.0	0.0	0.0
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	108,100.6	48,892.8	44,030.3	2.3	0.0	1,977.5	1,700.4	9,530.1	7.1	408.2	249.6	1,222.8	79.6	0.0	0.0
2.2 Delivery Demand HP	97,448.4	48,892.8	44,030.3	2.3	0.0	1,977.5	1,700.4	0.0	7.1	408.2	249.6	0.0	79.6	100.7	0.0
2.3 Delivery Demand LP	96,220.4	48,892.8	44,030.3	2.3	0.0	1,977.5	472.5	0.0	7.1	408.2	249.6	0.0	79.6	100.7	0.0
2.4 Cust. Rel Plant	1,984,734.0	1,826,796.0	157,500.0	9.0	0.0	201.0	30.0	5.0	38.0	108.0	38.0	1.0	7.0	1.0	0.0
STORAGE RESPONSIBILITY															
3.1 Deliverability	50.8	27.7	22.0	0.0	0.0	0.4	0.1	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0
3.2 Space	2,823.6	1,298.0	1,358.9	(0.1)	0.0	32.2	17.4	0.0	0.0	26.9	51.5	38.8	0.0	0.0	0.0
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1,984,734.0	1,826,796.0	157,500.0	9.0	0.0	201.0	30.0	5.0	38.0	108.0	38.0	1.0	7.0	1.0	0.0
4.2 Services	1,982,400.0	1,784,240.1	195,204.2	18.4	0.0	1,066.4	255.1	3.1	254.8	682.9	618.3	0.0	40.3	16.3	0.0

Allocation Percentages
December 31, 2012

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
	FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	1.0000	0.5618	0.3986	0.0002	0.0000	0.0098	0.0000	0.0000	0.0001	0.0032	0.0076	0.0188	0.0000	0.0000	0.0000
1.2 Bundled Annual Deliveries	1.0000	0.4067	0.4235	0.0001	0.0000	0.0433	0.0472	0.0000	0.0049	0.0137	0.0461	0.0144	0.0000	0.0000	0.0000
1.3 Total Annual Deliveries	1.0000	0.4056	0.4223	0.0001	0.0000	0.0432	0.0471	0.0000	0.0049	0.0137	0.0460	0.0144	0.0000	0.0027	0.0000
1.4 Bundled Transportation Deliveries	1.0000	0.5140	0.4327	0.0001	0.0000	0.0206	0.0013	0.0000	0.0028	0.0054	0.0073	0.0158	0.0000	0.0000	0.0000
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	1.0000	0.4523	0.4073	0.0000	0.0000	0.0183	0.0157	0.0882	0.0001	0.0038	0.0023	0.0113	0.0007	0.0000	0.0000
2.2 Delivery Demand HP	1.0000	0.5017	0.4518	0.0000	0.0000	0.0203	0.0174	0.0000	0.0001	0.0042	0.0026	0.0000	0.0008	0.0010	0.0000
2.3 Delivery Demand LP	1.0000	0.5081	0.4576	0.0000	0.0000	0.0206	0.0049	0.0000	0.0001	0.0042	0.0026	0.0000	0.0008	0.0010	0.0000
2.4 Cust. Rel Plant	1.0000	0.9204	0.0794	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
STORAGE RESPONSIBILITY															
3.1 Deliverability	1.0000	0.5464	0.4325	0.0000	0.0000	0.0084	0.0025	0.0000	0.0000	0.0000	0.0000	0.0103	0.0000	0.0000	0.0000
3.2 Space	1.0000	0.4597	0.4813	0.0000	0.0000	0.0114	0.0062	0.0000	0.0000	0.0095	0.0182	0.0138	0.0000	0.0000	0.0000
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1.0000	0.9204	0.0794	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
4.2 Services	1.0000	0.9000	0.0985	0.0000	0.0000	0.0005	0.0001	0.0000	0.0001	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000

PENSION FUNDING COST VARIANCE ACCOUNT

1. The Company filed evidence at Exhibit B, Tab 2, Schedule 5, Z Factor Pension Funding Requirement explaining the request of a Z factor in relation to its pension funding position.

2. The Company is requesting $16.6 million of pension funding requirement to be included within the IR revenue determination for recovery within rates in 2012. The amount is based upon an estimate of a December 31, 2011 annual cost certificate of the pension fund and potential pension funding obligations. /u

3. In conjunction with this request the Company is also proposing a 2012 variance account treatment around the amount. The reason for this is that the actual December 31, 2011 annual cost certificate and funding requirement will not be available until February 2012 at the earliest. The variance account would capture the difference between the amount being recovered within rates and the actual funding requirement, with the difference being cleared to ratepayers along with all other deferral and variance accounts.

4. This treatment will ensure that ratepayers are paying no more than the actual cost of the required funding. Please refer to Exhibit B, Tab 2, Schedule 5, Z Factor Pension Funding Requirement for further details and explanation of the Company's proposal.

Witnesses: K. Culbert
S. Kancharla
A. Patel