Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2006-0034

IN THE MATTER OF AN APPLICATION BY:

ENBRIDGE GAS DISTRIBUTION INC.

2007 RATES

DECISION WITH REASONS – PHASE 1

July 5, 2007

Summary of the Decision with Reasons[1]
(EB-2006-0034)

Application	Board Decision
• Degree Day Forecast Methodology	• Approved for each service region, as per amended proposal
• Average Use per Customer	• Approved, to be amended for approved degree day forecast
• General Service and Contract Sales	• Approved, to be amended for approved degree day forecast
• Fuel Switching program expenditures	• Expenditure levels to be managed by Enbridge but must meet Total Resource Cost test
• Energy Link program	• Not approved. Cease program • Recovery of costs incurred
• Gas Supply Risk Management program	• Not approved. Cease program • Recovery of $0.691 million
• 2007 Open Bill Access Deferral account • 2006 Electric Program Earnings Sharing Deferral Account • 2006 Unbundled Rate Implementation Cost Deferral Account • 2006 Alliance Vector Appeal Costs Deferral Account • 2005 and 2006 Gas Distribution Access Rule Deferral Accounts	• Approved as proposed • Approved as proposed • Approved as proposed • Approved as proposed • Approved as proposed
• 38% Equity Component of Capital Structure	• Increase equity component from 35% to 36%
• Revenue to Cost Ratios	• Approved as proposed
• Access to Bill envelope to include inserts by third parties	• Approved with changes
• Rate Implementation	• Recovery of approved revenue deficiency/new rates effective January 1, 2007

[1] This summary (i) excludes the particulars in the 2007 Settlement Proposal and (ii) does not form part of the Decision nor does it itemize all findings and is not to be relied on for the purpose of applying or interpreting the Decision.

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EB-2006-0034

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2007.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

JULY 5, 2007

INTRODUCTION

The Application

Enbridge Gas Distribution Inc. (“Enbridge”, or “the Company”) filed an application dated August 25, 2006 with the Ontario Energy Board (the “Board”) under section 36 of the *Ontario Energy Board Act, 1998*; S.O. c.15, Schedule B, for an order or orders approving or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas for Enbridge’s 2007 fiscal year commencing January 1, 2007 (“2007 test year” or “test year”). The Board assigned file number EB-2006-0034 to the Application.

Appendix A contains details regarding some of the procedural aspects of the rates Application, including a list of witnesses and a list of participants.

The Settlement Proposal

On January 24, 2007, a Settlement Proposal was filed with the Board. During the course of the oral hearing, the parties to the Proposal filed four appendices regarding supplemental completely or incompletely settled items, one regarding issue 6.3, and three regarding issues 7.1 through 7.5. They are included as Appendices C to F of the Settlement Proposal. Appendices C and D are dated February 12, 2007, Appendix E is dated February 20, 2006, and Appendix F is dated March 21, 2007.

A copy of the Settlement Proposal, including the addenda, is attached as Appendix B.

Of the 47 issues on the Issues List, the Settlement Proposal includes the complete settlement of 30 issues and indicated that parties would not address these issues at the hearing. There were 7 issues for which there was a partial settlement, and the parties were unable to reach agreement on the remaining 10 issues.

Below is a list of issues which are presented in the Settlement Proposal as having been completely settled. The Board accepts the cost consequences of the Settlement Proposal and will not review these issues in this Decision.

Issue 1.1	Appropriateness of the Proposed 2007 Rate Base Amounts
Issue 1.3	2007 Safety & Integrity Project Budget Amounts
Issue 1.4	Board Method of dealing with Leave to Construct Applications in Separate Proceedings
Issue 1.5	Meeting requirements of the Board for Independent Cost Benchmark Study for the EnVision Project
Issue 1.6	Appropriate levels of Cost and Benefits for EnVision Project, and how are they to be reflected in rates
Issue 1.7	Justification of total Project Amount of $133 million for Automatic Meter Reading (“AMR”) Project
Issue 1.8	Appropriateness of proposed recovery amount of AMR in 2007 Rates
Issue 2.1	Appropriateness of 2007 Transactional Services Revenue and Sharing Mechanism from 2006 Decision
Issue 2.2	2007 Other Revenue Forecast
Issue 3.1	Gas Cost Forecast and Reference Price
Issue 3.5	Human Resources Costs
Issue 3.7	Corporate Cost Allocation for 2007
Issue 3.8	Regulatory and OEB Related Costs for 2007
Issue 3.9	Decision to Change to December 31 Taxation Year
Issue 3.11	Change in Depreciation Rates for 2007
Issue 3.14	Amounts included in Rates for Capital and Property Taxes
Issue 3.15	Amounts in Rates and methodology for Income Taxes
Issue 4.1	Appropriate Return on Equity for the 2007 Test year

Issue 5.1	Appropriateness of Cost Allocation based on Board Approved Methodology
Issue 5.2	Level of Recovery of Amounts for Demand Side Management Costs in Delivery Charges
Issue 6.1	Delivery Demand Charges
Issue 6.3	Rate Handbook Contents
Issue 6.4	Treatment of Bundled Transportation Charges and T-service Credit
Issue 7.1	Customer Care/CIS – has Enbridge complied with the direction in EB-2005-0001
Issue 7.2	Customer Care/CIS - Actions or Decisions required to prevent duplicated items in Regulatory Asset Account
Issue 7.3	CIS – Appropriateness of Forecast Costs
Issue 7.4	Customer Care/CIS-Appropriate Costs
Issue 8.1	Actions necessary to appropriately reflect the impact of the Decisions of the NGEIR (EB-2005-0551) Proceeding
Issue 8.2	Actions necessary to appropriately reflect the impact of the Decisions of the DSM (EB-2006-0021) Proceeding
Issue 9.2	Setting of Interim Rates, effective January 1, 2007

This Decision with Reasons will address the non-settled issues under the following chapters:

- Forecast of Degree Days
- Average Use-Per-Customer
- Contract Gas Volume and Revenue Forecast
- General Service Volume and Revenue Forecast

- Fuel Switching
- EnergyLink Program
- Open Bill Access
- Risk Management Program
- Deferral and Variance Accounts
- Capital Structure and Cost of Capital
- Revenue to Cost Ratios
- Rate Implementation

On April 16, 2007, the Board issued Procedural Order No. 8, dealing with the settlement of Issue 3.6 (Regulatory Cost Allocation Methodology). Parties had indicated in the settlement that they were unable to reach a settlement on Issue 3.6. The Board ordered that Issue 3.6 will be considered as part of a separate phase (Phase 2), and consequently, Issue 3.6 is not addressed in this Decision. The ultimate resolution of this issue will not affect 2007 rates.

Interim Rate Order of March 26, 2007

The Settlement Proposal included the agreement from all parties that:

> … for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. GEC's and Pollution Probe's agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1. (Ex.N1 Tab1 Schedule 1 p9 /filed January 24, 2007)

An Interim Rate Order was issued on March 26, 2007 and is attached as Appendix C to this Decision.

Submissions and exhibits

Copies of the evidence, exhibits, arguments, and transcripts of the proceeding are available for review at the Board's offices.

The Board has summarized the record of the proceeding only to the extent necessary to provide context to its findings.

FORECAST OF DEGREE DAYS

The forecasting of degree days establishes the basis on which the Company can project its expected revenues and from that derive its projected sufficiency or deficiency.

Issue 2.3 reads “Is the forecast of degree days appropriate?”

The Company originally proposed to use the Central region degree day forecast of 3,617 degree days based on the 20-Year Trend method. In addition to the Central region application this forecasting methodology would apply to both Niagara and Eastern regions. The use of this forecast methodology would result in a revenue deficiency of $12.9 million, compared to the last Board-approved degree day forecast.

In its argument–in-chief, the Company amended its proposal by requesting approval of separate forecasting methodologies and forecasts for its Niagara and Eastern regions.

The nine methods evaluated by the Company are: the Naïve method, 10-Year moving average method, 20-Year moving average method, 30-Year moving average method, 50/50 method[2], de Bever method[3], de Bever with Trend method[4], 20-Year Trend method and the Energy Probe method[5]. The Company compared the actual degree days with the forecast degree days for each methodology for each year for the 1990 to 2005 period. The Company then ranked these methods using the following measures: Accuracy (as represented by Mean Absolute Percent Error and Root Mean Square Percent Error), Symmetry (as represented by Mean Percent Error and Percent Over-Forecast) and Stability (as represented by Standard Deviation).

[2] Also referred to as the Union method, is a weighted average of the 20-Year Trend method and the 30 Year Average.
[3] “The de Bever [method] is a regression model and features a long-term and short-term component. The former takes the form of a constant, while the latter is accomplished via a five-year weighted average of degree days (lagged two years). The model is estimated over a period equal to the estimated periodicity of the weather cycle”. C2/T4/S1
[4] “The de Bever with Trend [method], as the name implies, adds a trend variable to the previously approved de Bever method”. C2/T4/S1
[5] “Energy Probe [method] adds both a trend and a five-year simple moving average to the basic de Bever model”. C2/T4/S1

Based on its review, the Company now proposes to use a mix of degree day forecast methodologies. The Company argues that its analysis indicates that it is appropriate to move away from using the de Bever methodology and in its place the Board should adopt the method that is best suited to each of its three regions. Accordingly, the Company is requesting approval for the 20-Year Trend method (and forecast of 3,617 degree days in the Central region), the Energy Probe method (and forecast of 4,410 degree days) in the Eastern region and the 50/50 method (and forecast of 3,546 degree days) in the Niagara region. This new proposal reduces the revenue deficiency related to weather from $12.9 million to $11.7 million.

While intervenors and Board Staff have raised a number of issues with the Company's proposal, the majority of the discussion has focused on the proposed use of the 20-Year Trend method in the Central region.

The Company argues that the current Board-approved method, which was approved in 1990, is no longer appropriate to accurately predict an increasingly volatile and downward trend in heating season degree days.

The Company presented evidence to support its claim that, in recent years, weather has become increasingly volatile and exhibits a warming trend. The Company also presented detailed empirical evidence based on its examination of the different methods. Its analysis, the Company argued, clearly indicates that the 20-Year Trend method produces better forecasts than any of the other methods for the Central region.

Schools and CCC argued that the Company has not made a case sufficient for the Board to adopt a new methodology, particularly a complex mix of various approaches. While Schools accepted the use of a linear trend to forecast degree days, it raised a number of issues with respect to the methods tested, the design of the ranking system, and the length of the test period. Schools also argued that the Board should adopt an interim solution and the issues of weather risk and degree day forecasts should be addressed in a generic proceeding.

CCC submitted that Enbridge has not demonstrated that the 20-year trend is a sufficiently robust and flexible model and that the Board should continue with the de Bever methodology, or set the 2007 degree day forecast using the methodology approved by the Board for Union Gas.

IGUA argued that the Company should not be allowed to change its degree day methodology before the results of the Board's pending weather normalization review are known. IGUA argued that Enbridge's forecast should be determined based on the methodology currently embedded in its rates. IGUA characterized this methodology as the "adjusted" de Bever methodology and it consists of reducing the forecast produced by an application of the Board approved de Bever methodology by 43 degree-days. Accordingly, IGUA argued the 2007 degree day forecast should be 3,805 degree days.

Board Staff identified certain concerns with the Company's proposed methodology, but did not advocate the use of any one particular method.

Energy Probe supported the Company's proposal to use the best performing method in the three regions. However, it argued that the analysis used to assess the performance of the different methodologies, is flawed. Energy Probe submitted that the Board should approve the Energy Probe methodology for the Central and Eastern regions and the 10-year moving average methodology for the Niagara region.

Board Findings

The Board considers the following to be the two issues to be considered with respect to the proposed change in methodology: Has the Company made a sufficient case to alter the currently used methodology? If it has, then what is the appropriate degree-day forecasting methodology (or methodologies) for setting test year rates? The Board deals with each question below.

Has the Company made a sufficient case to alter the currently used methodology?

CCC submits that Enbridge has not made a case sufficient for the Board to adopt a new methodology, particularly a complex mix of various approaches. Schools argues that the Board has an approved degree day forecasting method for Enbridge which was established after a thorough debate with expert evidence and that, from a strict legal point of view, the de Bever method is the default method; since the Company has not met the onus to supplant it, the de Bever method should be used. IGUA, supported by VECC, argues that pending the results of the weather normalization review, Enbridge's forecast should be determined based on the methodology currently embedded in its rates.

The Company argues that it has presented detailed evidence to indicate that the current method is no longer appropriate and notes that those are sufficient grounds to warrant a change in methodology. In response to IGUA's arguments, the Company argues that no such methodology has ever been presented or approved by the Board. The Company further argues that in the years since 2003 the degree day forecasts have been settled and are not premised in any degree day forecasting methodology.

The Board notes that the settlement agreement in the last rates case for the Company (EB-2005-0001) does not make any specific characterization nor does it explain the basis for the degree day adjustment agreed to by the parties from the level proposed by the Company. It merely notes that the parties have agreed to reduce the degree day forecast by 43 degree days. The Board considers the adjustment to be the result of a negotiated settlement rather than being underpinned by any scientific or statistical reasons.

The Board believes that given that the sole purpose of a forecasting methodology is to accurately forecast weather it is simply appropriate to select a method based on the empirical findings.

In the Boards view, the aforementioned evaluation of nine various methodologies presented by the Company reasonably demonstrates that the de Bever method has not produced the most accurate forecasts compared to other methods.

What is the appropriate degree-day forecasting methodology (or methodologies) for setting test year rates?

Having found that the utility has made a compelling case to consider a change in methodology, the Board then must make a determination on an appropriate degree day forecasting methodology.

The Company has presented historical weather data and argues that this data reveals that weather is increasingly volatile and displays a warming trend, especially in the Central region. The Central region is particularly relevant in this context, because it accounts for over 80% of the Company's volumes.

The Board is satisfied that the historical weather data presented by the Company can be interpreted to support the premise that an underlying warming trend and increasing volatility in weather does exist. However, the Board does not find this to be determinative in the selection of the most appropriate model. The Company has presented various methods. Some of these are based on simple moving averages, while others are more sophisticated.

Based on the evidence and arguments, the Board concludes that a linear trend method is an appropriate method to be used. The moving average methods, while they do capture the trend, exhibit a considerable lag, thus making it an inferior method to the linear method. While the Naïve method captures the randomness in the data, it can result in an abrupt and substantial change, which could lead to rate shock. The de Bever method, as noted earlier also has its limitations.

The selection of the trend is a critical factor in the determination of an appropriate forecast. The evidence the Company has presented indicates that a linear regression trend based on 20 years of data, compared to the other eight commonly used methods, generates forecasts that display greater accuracy. for the Central Region having accepted the analysis presented by the Company as part of its review of the nine comparable methodologies, the Board accepts the Company's amended proposal to apply the 20-Year Trend method in the Central region, the Energy Probe method in the Eastern region and the 50/50 method in the Niagara region.

AVERAGE USE-PER-CUSTOMER

This section addresses Issue 2.4, namely, Are the average use-per-customer forecasts for Rate class 1 and Rate class 6 appropriate?

A key element in the Company's forecast of its General Service sales volumes for the 2007 test year is the forecasted average use for Rate 1 and Rate 6 customers. The Company indicated that the models it employs to forecast average use have been in use since 2001 and that, during that period, parties and the Board have accepted these models through the Board-approved Settlement Proposals. Excepting the years 2001 and 2005, in which there were high and volatile gas prices, the average error variances between normalized actual use and Board-approved was less than 1%, indicative of the model's accuracy and validity.

The Company's 2007 forecast of volumes for general service customers was prepared in the spring of 2006, incorporating the most up to date information available when the filing was prepared. At that time, the Company used the PIRA Energy Group's price forecast for Henry Hub Spot which was published in January 2006. This was the most recent information available when the Company put together its volume forecast budget in April 2006.

The Company's evidence forecast a continuing decline in average use.

The Company noted that its 2007 General Service sales volumes forecast reflects a decrease of 99 million cubic metres, as compared to the 2006 estimate, due to declining average use per customer.

Efficiency of gas appliances and relatively high and volatile gas prices were identified by the Company as key reasons for the decline in average use.

The Company's evidence indicated that gas prices accounted for 62% of the decrease in Residential gas consumption and for 19.9% of the decrease in apartment /commercial/ industrial gas consumption.

Positions of the Parties

While no intervenors disputed the integrity of the average use model the Company used to generate its average use forecast, VECC and Energy Probe questioned the timeliness and source of the gas price forecast which was reflected in the model utilized to forecast average use. Their submissions received the support of IGUA, Schools and CCC.

VECC expressed concern with the forecasted decline in normalized average use and volumes in the residential and apartment sectors, and highlighted the projected increase in natural gas prices as the dominant factor driving the forecasted decrease in general service volumes. In this regard VECC submitted that Enbridge made two material errors when forecasting the normalized average use for residential (Rate 1) customers by i) relying on the PIRA Energy Group forecast as opposed to the Board approved QRAM price forecasts, and ii) relying on forecasts from Q1, 2006 when materially different actual and forecasted natural gas prices for 2006 and 2007 are available.

Energy Probe submitted that the real energy price forecast, a key input into the regression models for both the Rate 1 and Rate 6 average use equations, should be updated to reflect the most recent information available on the basis that it has a material impact. Energy Probe expressed concerned with the timing of the information used to prepare the 2007 test year average use per customer forecast. Although accepting the view held by Enbridge's witnesses that it is not possible to update the entire rate filing, Energy Probe argued that it is appropriate to update for significant changes that have taken place since April of 2006.

The Company disagreed with the intervenors' assertion that the gas price forecasts should be updated to reflect more recent information. The Company noted that the nature of forward test year cost of service regulation is that all of the Company's budgets are set on a forecast basis and then submitted to the Board for approval. Selective updating, while less cumbersome and time-consuming than full blown update, could present a misleading or inconsistent picture and would encourage opportunistic behaviour by intervenors. In the Company's view, the fair approach in this case is to reject the intervenors call for selective updates and instead rely on the consistent information that was available at the time that the Company prepared its application.

Board Findings

The Board notes that no intervenor challenged the accuracy of the volumes put forward by the Company or the assumptions imbedded in the average use model. Nor does the Company question the accuracy of the volumes put forward by VECC and Energy Probe in the respective proposals. The differences in the proposals are in the source of the reference price and the timing of obtaining the reference.

The question before the Board is one of fundamental importance as it deals with the basic principles associated with the filing of an application and the interrelation and interdependencies of various application components.

In establishing fair and reasonable rates the Board considers many factors and weighs many pros and cons. One of these balancing exercises is the valuing of the use of the most recent and therefore most accurate data against the value of being able to complete application processes in a timely manner and with a degree of certainty by all involved that the original application will be heard as filed, except for pre-determined or exceptional circumstances.

In this particular case the intervenors representing consumer groups support the insertion of fresh information into the application which would result in higher projected usage and therefore a lower projected revenue requirement for the Company. One can easily imagine the Company putting forward the same type of proposition if during the proceeding it became clear that the starting assumption on gas forecast prices was a less favourable input than a current reference price indicated. In essence, the application in such a paradigm would remain a dynamic document until the record would be considered closed. Although such dynamism may be appropriate in certain circumstances, it is impractical in this context.

The Board accepts that the most recent data should be used in the preparation of an application in the establishing of rates. The Board does not consider the data updating propositions of Energy Probe and VECC to be practical. The Board accepts the Company's position that there are too many interrelated matters and assumptions that must be taken into account if it were to update the particular elements argued for in its rates application.

The Board accepts the Company's average use-per-customer forecasts.

CONTRACT GAS VOLUME AND REVENUE FORECAST

This section deals with Issue 2.5, namely, Is the proposed 2007 contract gas volume and revenue forecast appropriate?

Contract customers are customers with annual consumption of 340,000 m^3 or greater who enter into a service contract with the Company and are in the 100, 200 and 300 series of rates. The volume forecast was prepared in March 2006, and incorporated the most up to date information available at the time when the filing was prepared.

In its pre-filed evidence, the Company sought approval of its contract gas volume forecast 4,131.7 10^6m^3 for the 2007 test year. Subsequently, in its argument-in-chief, the Company increased the forecast to 4,134.3 10^6m^3 to reflect the Company's amended degree days forecast proposals.

The Company characterised the development of the volume forecast for the contract market as a grass roots approach; it is prepared by aggregating the information collected by its account executives in consultation with all contract customers. The aggregate contract gas volume budget that results is then adjusted to take account of the degree day forecast on the weather-sensitive portion of the customers' forecast volumes to form the total contract volumes forecast for the test year.

IGUA submitted that it had no quarrel with Company's 2007 contract gas volume forecast apart from the weather projection methodology used to derive a forecast of 3,805 degree days for the weather sensitive portion. No other intervenors made submissions.

The Board accepts the non-weather sensitive component of the 2007 contract gas volumes forecast as filed. The Board directs the Company to reflect the 2007 test year contract sales volume forecast consistent with the Board's findings in the Forecast of

Degree Days chapter of this Decision pertaining to the degree day methodology the Company is to use to forecast weather sensitive volumes.

GENERAL SERVICE VOLUME AND REVENUE FORECAST

This section deals with Issue 2.6, namely, Is the proposed 2007 General Service gas volume and revenue forecast appropriate?

The Company in its pre-filed evidence sought approval of its General Service volume forecast of 7,625.8 10^6m^3 for the 2007 test year. Subsequently, in its argument-in-chief, the Company increased it to 7642.0 10^6m^3 to reflects the Company's amended degree days forecast proposals.

The Company indicated that the forecast was derived using regression models (average use) for Rates 1 and 6 and a forecast for Rate 9 consistent with past practices.

Intervenor and Company submissions focused on the Degree Day forecast and average use forecast, both of which are major inputs into the General Service forecast.

General Service volume forecast relates to degree day methodology and the derivation of use per customer amounts for the 2007 test year. The Board's findings in this regard are found in the Forecast of Degree Days and Average Use-Per-Customer chapters of this Decision. No submissions were made regarding other aspects of the General Service forecast.

The Board directs the Company to update the 2007 test year General Service forecast commensurate with this Decision as it pertains to degree day methodology and use per customer amounts.

FUEL SWITCHING

The settlement proposal approved by all parties other than GEC and Pollution Probe reduced the Company's proposed "Other O & M Budget" for the 2007 test year from $200.8 million to $181.5 million. Parties other than GEC and Pollution Probe agreed that they would not take any position as to how the Company should allocate this $181.5 million. Out of the $181.5 million approximately $3 million relates to fuel switching.

At the oral hearing Enbridge indicated that it will have to consider how it will allocate the $181.5 million amongst its different departments as a result of the Settlement Agreement. Consequently, the Opportunity Development budget, which subsumes fuel switching, would be allocated an amount lower than the $30.8 million budgeted in the pre-filed evidence.

Positions of the Parties

All parties with the exception of GEC and Pollution Probe agreed that Enbridge should have the required flexibility to allocate the envelope amount of $181.5 million.

GEC and Pollution Probe argued that the Board should approve Enbridge's fuel switching budget as filed and earmark an additional $11.5 million for incremental fuel switching expenditures as part of a joint Enbridge/OPA fuel switching program. Pollution Probe cited several benefits of fuel switching including reducing greenhouse gas emissions by reducing the demand for electricity, lowering natural gas distribution rates and reducing the need for new high-cost natural gas-fired power plants. Accordingly, GEC and Pollution Probe argued:

1. The Board should approve Enbridge's fuel switching budget as initially filed minus the costs associated with those programs that fail the Total

Resource Cost (TRC) test. This includes outdoor barbeques, garage heaters, pool heaters and gas fireplaces.

2. The Board should approve an additional $11.5 million of fuel switching expenditures.

3. The Board should establish a variance account with respect to Enbridge's fuel switching budget that returns any of the unspent dollars to ratepayers, and

4. The Board should direct Enbridge to evaluate the actual TRC net benefits of its fuel switching programs at the end of fiscal 2007. Enbridge should also be subjected to the evaluation and auditing process similar to a Demand Side Management ("DSM") program.

VECC was a signatory to the Settlement Agreement on Other O&M but kept its options open to advance arguments that the Company allocate the budgeted amount of $925,000 for Low-Income fuel switching initiatives. VECC argued that according to the settlement reached in the generic DSM proceeding, Enbridge was committed to budget a minimum of $1.3 million, or 14% of its residential DSM program budget, whichever is greater, for low-income customer programs. Accordingly, Enbridge should commit to spend the budgeted amount of $925,000 on Low-Income fuel switching initiatives as stated in the pre-filed evidence. VECC submitted that in order to ensure success of Low-Income fuel switching programs, a minimum amount needs to be spent so as to reach a critical mass of customers. According to VECC this amount is much higher than 14 percent of the residential program budget that Enbridge committed to spending at the oral hearing. VECC argued that this proportion should be close to 30%.

The Company in its Argument-in-Chief maintained that it required flexibility to allocate its budgets within the Other O&M envelope. Enbridge argued that its managers must have the flexibility to respond to changing market conditions and ensure a reliable and safe natural gas system. Enbridge rejected suggestions of GEC and Pollution Probe of setting up a variance account to track the money spent on fuel switching activities citing that the Company should not be locked in terms of spending on a particular area.

The Company further maintained that the Board should not micro-manage Enbridge's budget on a program-by-program basis. It also rejected suggestions of spending additional expenditures on fuel switching activities. The Company indicated that the Other O&M envelope of $181.5 million is the level of spending that ratepayer groups are prepared to accept and the Company has to work within this envelope in determining its budget priorities. Spending additional amounts will lead to short term rate impacts that the ratepayer groups are not prepared to accept.

The Company also rejected the recommendation of some intervenors that Enbridge should not pursue load growth or fuel switching programs that generate a negative net TRC. According to the Company, the TRC analysis does not work with respect to many load growth programs and therefore does not assist in the determination of whether the program should be continued or not. One example that the Company cited in its Argument-in-Chief was the proposed residential fireplace program. Although the program has a favourable Net Present Value (NPV), it does not pass the TRC test. The Company has argued that if the TRC measure is used as the determining factor then the Company would have to discontinue all its activities with respect to natural gas fireplaces. The Company maintained that if it is prohibited from implementing all programs that generate a negative TRC, then it would have to discontinue the electronically commutated motor program ("ECM") which increases the efficiency of the motor on a furnace saving electric load, while incrementally adding additional gas consumption. The Company further added that this program has been strongly supported by intervenors in the past.

The Company also referenced the California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects that points to the weaknesses of the TRC test in evaluating load growth initiatives. The Company indicated that it puts greater emphasis on NPV as an appropriate measure for load growth and fuel switching initiatives as it provides a better basis to assess whether the program will not be a financial burden on ratepayers. Based on the above argument, the Company asked the Board to reject any suggestions that it be prohibited from undertaking programs that support the lawful use of natural gas appliances by its customers.

Board Findings

In the 2006 Rate Case (EB-2005-0001), the Board did not look at individual departmental budgets to determine its findings on Enbridge's Other O&M. Rather it looked at cost per customer. The Board noted on Page 97 of the Decision:

> The Board expects that productivity improvements, or budget prioritization, will allow Enbridge to manage cost pressure within this envelope.

The Board did not allocate specific amounts to different departments and relied on Enbridge to decide on how best to manage its operations within a specific envelope. In the current proceeding, Enbridge and other parties have agreed to an envelope amount of $181.5 million to meet the Company's Other O&M requirements. The Board does not see any reason for micro-managing Enbridge's budget. Enbridge has been allocated an envelope amount and requires sufficient flexibility to meet its operational priorities. The Board will therefore not make any determination on the amount that Enbridge should spend on fuel switching initiatives and will neither ask Enbridge to set up a variance account to track expenses on such initiatives.

In making this finding, the Board rejected GEC and Pollution Probe's recommendation that Enbridge should be asked to significantly ramp up its spending on fuel switching initiatives and spend an additional $11.5 million on such initiatives. Although such initiatives can provide additional benefits, there is no evidence to suggest that Enbridge can spend more money in a cost-effective way on fuel switching in the interests of ratepayers.

GEC and Pollution Probe's recommendation that Enbridge should not be allowed to promote fuel switching and load growth initiatives with appliances that fail the TRC test has merit. Promoting appliances with a negative TRC seems inconsistent with the Government of Ontario's goal of creating a culture of conservation and carries negative societal benefits in terms of increasing emission of greenhouse gases. Accordingly, the Board directs Enbridge to pursue only those initiatives that meet the TRC test.

Enbridge's claim that if it is prohibited from implementing all programs that generate a negative TRC, then it would have to discontinue the electronically commutated motor program ("ECM") is not correct. Although the TRC may be negative in the case of the ECM program, this initiative is not evaluated separately from the furnace. Consequently, the high-efficiency furnace that uses an ECM has a positive TRC. This is not the case for a natural gas fireplace, barbecue, outdoor heater or a pool heater.

The Board does not see any need to evaluate the actual TRC net benefits of Enbridge's fuel switching programs at the end of fiscal 2007. The Board has recently approved a three-year DSM framework for Enbridge and Union. One of the key reasons for implementing a three-year framework was to avoid detailed ongoing scrutiny of the utility's DSM programs. It would be inappropriate to move backward and subject Enbridge's fuel switching initiatives to the prior level of scrutiny afforded to DSM.

The final matter to be addressed in this section of the Decision concerns the VECC argument regarding the minimum amount that the Company should be spending on fuel switching for low income groups. VECC essentially argues that the reduction in the O & M budget agreed to in the Settlement Proposal should not be applied to this segment and suggests that the minimum amount should be closer to $925,000 which is close to 30% of the total amount. The Board does not accept this submission but does accept the submission that the amount of fuel switching expenditure on low income groups should be not less than 14% approved by the Board in the generic DSM Decision pertaining to DSM programs. In making this finding, the Board is not making a nexus between DSM and fuel switching other than the 14% level also being an appropriate allocation of expenditures geared to lower income groups.

ENERGYLINK PROGRAM

EnergyLink is a channel partnership with HVAC contractors intended to assist Enbridge customers find natural gas solutions using a referral system that can be accessed either through the Internet or the Company's call centre. Customers are given a choice of three service providers who meet their requirements.

The Company initiated a phased roll-out of EnergyLink. The first phase which included customer referrals for natural gas furnaces, boilers, fireplaces and water heaters, as well as referrals for installation of natural gas appliances was launched in December of 2006. In the second phase, the Company will create a retailer locator that will help customers find retailers of natural gas appliances.

Enbridge has budgeted an amount of $1.3 million in O&M spending on EnergyLink and a further $2.75 million in capital expenditures. A partial settlement was reached for the 2007 capital budget and the overall level of "Other O&M". However, capital and O&M spending on the EnergyLink program remained unsettled items other than the agreement that the Board's decision in this matter would not impact the overall test year capital or O&M budget.

With the exception of GEC and Pollution Probe, intervenors did not support the EnergyLink program. The main issues are as follows:

1. Whether the Board approved the program in its Decision in EB-2005-0001 or otherwise?

2. If the Board has not approved the EnergyLink program, should the Board now approve this program?

3. If the Board does not approve the EnergyLink program, should the costs incurred be recovered from the ratepayers?

Positions of the Parties

CCC disagreed with the Company that the Board has approved the EnergyLink program. According to CCC, Enbridge did not provide detailed evidence in the 2006 rate case of what the EnergyLink program consisted of so that the implications of approving the program could be fully examined. In Union Energy's view, Enbridge cannot pursue EnergyLink without prior Board approval and in the event that Enbridge seeks Board approval, it should not be permitted to allocate funds from either the 2007 Capital Budget or the Other O&M Budget to EnergyLink. VECC, based on its calculations of unit costs of $60 per call or $20 per contractor referral, argued that these unit costs appeared to be high and it was not clear that EnergyLink was a cost-effective service for ratepayers.

CCC, HVAC, and IGUA are concerned about the risk of an anti-competitive impact from this program. They argued that the customers would associate the EnergyLink program with Enbridge and think that it is the primary source of service for gas-fired equipment.

HVAC specifically argued that companies who promote their own brand name face a new hurdle, namely one of having to compete with the powerful Enbridge/EnergyLink brand. HVAC companies will have to make a decision whether to market under the EnergyLink brand or their own brand, with the latter option being significantly more expensive. In addition, Enbridge will restrict competitors' efforts to compete with the Enbridge/EnergyLink brand and will restrict advertising by third parties in Enbridge's envelope by preventing companies from mentioning EnergyLink.

Direct Energy argued that Enbridge should have continued to work with the contractor community and focused its efforts on marketing and promoting the benefits of natural gas, rather than developing a branded referral service that would compete against established marketing channels and existing referral services. Direct Energy stated that, like many other service providers, it felt compelled to join the EnergyLink program, given the potential for negative customer perception from not being accepted as a qualified contractor by Enbridge. However, having the benefit of full disclosure of the intent and scope of the program, Direct Energy submitted that it strongly opposes the continuation of EnergyLink and recommended that the Board disallow the further use of ratepayer dollars.

HVAC asked that the Board order the Company to terminate the EnergyLink program immediately and CCC submitted that the Board should not approve the EnergyLink program in view of its possible adverse impact on the competitive market.

Union Energy, HVAC and IGUA submitted that one of the major reasons for developing this program is to provide a platform for Enbridge Financial Services Inc.'s financing program and provide benefits to the unregulated affiliates of the utility. CCC argued that the returns to Enbridge's parent from the financing program of EnergyLink would be very substantial according to a presentation attached to an exhibit by the Company and that no part of the cost of the EnergyLink program should be recovered from ratepayers.

Union Energy and HVAC also questioned the projected success of the program. In reply to an Undertaking (J10.7), the Company indicated that it expects 1,200 customers to switch to a natural gas furnace from an electric or oil furnace as a result of the EnergyLink program. HVAC submitted that this forecast is unrealistic. The Company forecasts replacement of 36,191 furnaces from electric/oil to natural gas. Considering that 90% of Enbridge's households in their franchise area have a natural gas furnace, this would imply a replacement rate of over 20%. Since the life of an electric or oil furnace is 15 to 20 years, this indicates that switching is three to four times the normal replacement rate. HVAC and Union Energy submitted that Enbridge had not provided credible evidence as to how EnergyLink is going to cause these new sales.

HVAC also questioned the Company's forecast with respect to water heaters. The Company has two types of water heater programs, those in which an electric water heater is switched to gas and those under which a new water heater is installed, usually in new construction. The Company's direct programs forecast 1,518 participants and this program show a negative NPV (Exhibit J9.2). The reason for the negative NPV is the amount paid to participants as incentives. However, when the same program is being promoted through EnergyLink, the Company is projecting 2,500 participants (Exhibit J10.7). Since this program has a positive NPV, it indicates no incentives. HVAC argued that it is difficult to believe that a program that gives an incentive cheque to a customer will be significantly less successful than the EnergyLink program.

On the other hand, GEC and Pollution Probe submitted that they support the EnergyLink proposal as a means to facilitate DSM and fuel switching, and according to GEC, so long as the mechanism is not used to encourage inefficient end uses. Pollution Probe submitted that the Board's approval of the EnergyLink program budget should be conditional on Enbridge issuing a RFP to obtain competitive bids from financial institutions for low interest financing. GEC commented that the parties who are opposed to the EnergyLink program on the basis that it was a platform to channel financing opportunities to Energy Financial Solutions Inc. were signatories to a settlement allowing the on-bill financing proposal to proceed, presumably believing that any possible abuse of affiliate relationship and any corrosion of the competitive market due to bill-financing is protected against in that agreement. Accordingly, GEC submitted that it was puzzled by the suggestion of some parties that the EnergyLink program is a tool to destroy competition.

VECC stated that of the purposes for the EnergyLink identified by Enbridge, the provision of an easy connection for customers with service providers was the only goal which VECC accepted and that it does not disagree that an enhanced referral system located in the utility could be of benefit to customers, to the extent that it provides the 25,000 unsolicited calls from customers with referrals to qualified service/installation contractors.

IGUA and Union Energy argued that activities such as the rental of gas-fired equipment, the provision of a contract referral service, are not within the scope of business activities in which Enbridge can engage as a Board regulated natural gas transmission, distribution and storage utility, quoting the undertakings Enbridge gave the Lieutenant Governor in Council which were approved by Order in Council on December 9, 1998:

"….shall not, except through an affiliate, carry on any business activity other than the transmission, distribution or storage of gas, without the prior approval of the Board." Furthermore, IGUA, with respect to business activities pertaining to the rental of gas-fired equipment, quoted paragraph 3.2.5 from the Board's March 31, 1999 Decision with Reasons in E.B.O. 179-14/15: "The Board's finding with respect to retention of the rental program in the core utility is supported by its view of current regulatory policy, which encourages the development of a "pure utility", stripped of non-monopoly services……..Retaining the Company's rental program in the core utility does not allow appropriate costing principles to prevail." And according to paragraph 3.2.6 "The Board would accept the program, for the time being, on a non-utility basis within the Company, with elimination of the program's costs on a fully allocated basis." Union Energy submitted that the subsidy burden that EnergyLink imposes on ratepayers should be evaluated on a fully allocated cost basis and eliminated in its entirety from Enbridge's revenue requirement. IGUA argued that since the EnergyLink program is incompatible with the "pure utility" policy reflected in the Company's current undertakings, the utility is prohibited from carrying on any of the EnergyLink program activities without prior Board approval. VECC submitted that the Board should not approve the cost consequences of EnergyLink for 2007 since it is not a core distribution utility service.

The Company argued that it has already received approval for EnergyLink in the 2006 rate case. The Company did indicate then that it planned to introduce a channel strategy to facilitate natural gas solutions for customers. The Company did not however specifically mention the EnergyLink program. Before EnergyLink was launched by the Company, Mr. Hewson the Board's Chief Compliance Officer received a letter from the HVAC Coalition expressing concern about the program. Mr. Hewson indicated that it did not appear that EnergyLink was outside the requirement of the Gas Distribution Access Rule ("GDAR") or any other regulatory parameters within which Enbridge is permitted to distribute natural gas in Ontario.

With respect to the arguments by certain intervenors that based on the undertakings that the Company has given to the Lieutenant Governor in Council Enbridge cannot engage in a business activity other than the transmission, distribution or storage of gas unless it has prior Board approval, the Company indicated that there are a wide range of activities that the Company undertakes on a daily basis that support the core activities of the Company such as maintaining a fleet of vehicles or conducting financial studies. The Company submitted that EnergyLink falls precisely into the same category.

The Company reiterated that it is confronting a situation of market stagnation. Average use per customer has been declining and this is expected to continue due to the impact of conservation, updated codes and standards and higher and more volatile natural gas prices. This market stagnation has resulted in negative pressure on Enbridge's market share and throughput. To support its argument, the Company cited the decreasing penetration of gas water heaters in the customer replacement market and the increasing market share of electric fireplaces. EnergyLink would address these issues by increasing throughput and penetration of natural gas-fired appliances.

Another factor according to the Company that underlies the EnergyLink program is customer confusion about who to call for information regarding natural gas equipment and appliances. The Company indicated that customers see Enbridge as an unbiased party and a reliable provider of information[6]. Thus, it is no surprise that customers contact the gas utility for information on natural gas appliances. The Company has estimated that it receives 25,000 calls per year of this nature. EnergyLink would satisfy these customers by providing referrals to qualified contractors. More importantly, customers do not pay any fees for referrals and there is no charge to contractors to participate in the program.

The Company stressed the benefits of EnergyLink that it provides to ratepayers by increasing throughput. The program has a net present value of $4.1 million. The program provides a valuable service to customers and might assist customers in selecting a natural gas solution over an electric one. The Company also cited benefits to members in the form of free leads, free access to the EnergyLink brand, exclusive

[6] According to a survey done by Enbridge and filed in evidence, 75% of the Company's customers would trust Enbridge to provide reliable and credible information about contractors/retailers: Exhibit I-26-17, Attachment 3, page 8 of 19

sales campaigns, co-op advertising, access to training opportunities and other sales tools.

One issue specifically scrutinized by the intervenors was a proposal to offer a financing program whereby customers could finance their equipment purchase through the Enbridge bill. The Company indicated that Enbridge Solutions has still not made a decision about whether it intends offering a financing program and that EnergyLink is not a platform to launch an affiliate's financing program.

The Company argued that the issues raised by other parties have not demonstrated that the program is fundamentally flawed but rather the issues have merely created suspicions around EnergyLink. In that regard, in its reply argument, Enbridge made six commitments to the Board to address certain issues around this program:

1. Enbridge will send out an immediate communication to all EnergyLink contractors making it clear that they do not have to belong to EnergyLink to access the bill.

2. Enbridge will seek opportunities to encourage low interest financing for energy efficiency products or measures to be part of its market development activities and it will seek to include as many interested financing entities as possible.

3. Enbridge will investigate working with the TSSA in connection with independently qualifying these EnergyLink contractors.

4. Enbridge will establish an EnergyLink advisory group. This group will not be funded by ratepayers, but will be comprised of individual EnergyLink contractors to provide guidance and feedback and suggest continuous improvements to the program.

5. Enbridge will report to the Board in an appropriate time and fashion the following information: prior to launch, its plans regarding Phase II of EnergyLink with respect to retail options for natural gas white goods and

after completion of 2007, performance reporting including number of customers, number of referrals, customer satisfaction results, level of influence of EnergyLink, added load and DSM, and results of a contractor survey.

6. In full compliance with the Affiliate Relationship Code, Enbridge will continue to ensure that no non-public information about EnergyLink is communicated to any unregulated affiliate.

In response some intervenors submitted that the so-called “commitments” were materially new and untested. They were not introduced as evidence and should not be considered in this proceeding as they are inadmissible. The HVAC Coalition submitted that the commitments failed to address the fundamental problems with the EnergyLink program and its harmful impacts on the competitive marketplace and the Company’s ratepayers.

Board Findings

Enbridge is a leader in conservation initiatives in the Province and a considerable amount of consumer dollars are invested in this activity. The EnergyLink Program is designed to do exactly the opposite, namely to use consumer dollars to fund programs to increase the use of gas. In some cases, these projects would not meet the TRC standards that are used to evaluate their conservation initiatives. The result is that consumers would be receiving confusing messages and funding competing programs.

The other concern is the potential anti-competitive aspect of the EnergyLink Program. Much of this hearing centered on this issue. While the six commitments made by Enbridge in its reply argument attempt to address the anti-competitive concerns, these concerns continue to exist. There is no question that leads and inquiries go to the gas company and without a referral program many of these leads may be wasted. On the other hand, the evidence before the Board is that there is a growing and substantial industry capable of meeting market requirements. The unintended result of the Enbridge program might be to dampen this competitive development.

The Board finds that there is no clear evidence of market failure that requires the intervention of Enbridge through this Program. The Board is not convinced that the cost of the Program justify the benefits. The concern with declining average use remains of course. It should be addressed, in the Board's view in a more fundamental fashion as has been done in a number of jurisdictions that dealt with the issue of declining use.

Enbridge argues that the Board has accepted and approved the EnergLink Program in its previous rate case. The intervenors disagree. The evidence provided by the Company in that proceeding was limited. It is difficult to conceive that the Board intended to approve or approved a Program of the nature described in this hearing with its attendant costs based on the evidence, or lack of, that was before it. The Board will allow the Company however to recover the costs incurred to date but finds that no further costs should be recoverable from the ratepayers.

The Company indicated that it had budgeted $1.3 million in Operating and Maintenance expenses and $2.7 million in Capital expenditures for 2007 and that it estimates to have spent $3.3 million in capital in 2006. The Board finds that for ratemaking purposes the Company's 2007 Other Operating and Maintenance Budget shall be reduced by $1.3 million to $180.2 million. The 2007 rate base shall be updated to reflect the removal of any EnergyLink related capital expenditures. The Board understands that the Company in good faith has incurred actual costs in operating and maintenance expenses and capital expenditures related to the EnergyLink program and it would be unfair to the company to have to absorb these costs. The Board approves the recovery of the 2007 Operating and Maintenance expenses incurred as of the date of this decision, but no more than $1.3 million. The Board approves the recovery of capital expenditures, but no more than the 2006 estimated and 2007 budgeted amounts spent to the date of this decision. The balances will be amortized evenly over three years starting in 2007. The Company therefore shall include a rate rider as part of its draft 2007 rate order, with appropriate supporting documentation as to the calculation of the specific amounts.

OPEN BILL ACCESS

This section addresses the “non-settled” aspect of Issue 7.5. Issue 7.5, “Is the Applicant’s proposal of open bill access appropriate and consistent with the direction in EB-2005-0001” has two aspects, (i) third party billing information included on the Enbridge bill (“billing services”) and (ii) the inclusion of third party inserts in the Enbridge envelope (“inserts”). “Billing services” was completely resolved in the 2007 Settlement Proposal. “Inserts” was not.

Certain parties (Enbridge, Direct Energy, OESLP and Union Energy) agreed to settle the billing insert component on the basis that the Company can proceed with the Insert Service subject terms listed in Appendix D page 1 of the Settlement Proposal. HVAC, VECC and Schools did not agree with the proposed settlement and CCC opposed the settlement in order that it may be permitted to pursue cross examination on the issue. GEC and Pollution Probe reserved the right to pursue in the hearing whether the Board should order that third parties not be allowed to use the billing services for the billing of specific products on the basis of their environmental attributes. Superior opposed the proposed settlement on the principle that it is not supportive of a settlement position that would allow for the Company to promote system gas through billing inserts.

Open Bill Access was an issue in the 2006 test year proceeding (EB-2005-0001/EB-2005-0437). In that Decision, the Board indicated that although that there may be merit in sharing the bill with service providers, Enbridge had to make a more thorough case. The Board noted that concerns, including ratepayer benefits, impact on the public interest, the potential for customer confusion, non-discriminatory access, and interim versus comprehensive solutions needed to be addressed.

Positions of the Parties

The Company's basic justification for the program is to increase the use of natural gas to offset a declining rate of usage on a per customer basis through the promotion of sales of goods which utilize natural gas. According to the Company, the program will also fulfill the expectations of customers that Enbridge will provide them with information about natural gas products and services while providing them with the option of opting out from receiving such information. In addition, the Company asserts that the program will provide an additional ratepayer benefit through earnings sharing and lower cost of service, provide additional opportunities for DSM and enhance customer convenience and improve customer satisfaction.

Parties supporting the program submitted that the program would provide equal and fair access to both big and small vendors to the envelope and would be in the public interest given ratepayer financial benefits and customer communications.

GEC and Pollution Probe supported the program on condition that it not be used to promote inefficient products and services. The results should be TRC positive and consistent with DSM purposes.

Parties disagreeing with the program noted that the presence of third party inserts will obscure and dilute the impact of safety and regulatory inserts, will cause customer confusion, that survey data supporting customer interest in receiving the inserts is ambiguous and that the 50/50 income sharing arrangements are inadequate.

HVAC, as a potential user of the service, submitted that the Board direct the Company not to proceed with a bill insert service at this time because risks and inconveniences to ratepayers exceed any benefits, the program does not comply with the Board's direction in providing open access, the bidding process does not meet the test of being non-discriminatory, and the Company still has to demonstrate a bidding structure that accomplishes the goals of open access and revenue maximization. HVAC also raised the question of whether, in the first instance, it is appropriate for a utility to use its envelope to sell the services of private companies.

Board Findings

There are a number of criticisms of the procedures the Company developed for bill insert service.

There is no question that granting access to the bill for bill insert service can improve the competitive framework. That explains the reason the Program is supported by intervenors such as Direct Energy. There are complaints however by HVAC that the bidding structure for mid-size companies is not satisfactory. The Board believes that these concerns should be carefully investigated by Enbridge with a view to meeting the concerns of HVAC consortium in a revised bidding structure. Nonetheless, the Board believes that the Program is in the public interest subject to certain conditions expressed below.

First, there is a concern that crowding the bill with inserts tends to weaken the message for all participants and as a result a portion of the readers actually do not pay any attention to the inserts at all. The Board believes that the suggestion made by CCC has some merit and where a safety notice or rate increase is being publicized through a bill insert, no other material should be included in the bill for that particular mailing.

The Board also has some sympathy with the submissions made by GEC and Pollution Probe and agrees that access to Enbridge's billing envelope should be consistent with the Company's DSM Program and restricted to appliances so that they meet existing TRC tests. However, the Board concludes this would burden the initiative with an undue administrative oversight requirement and instead relies on the Company's exercise of discretion on this matter.

The last matter at issue is the income-sharing aspect. Enbridge proposes a 50/50 split in income received from the bill insert service. The infrastructure costs of this service are paid for by the ratepayers while the incremental costs are paid for by the companies seeking access to the bill. The Company forecasts the maximum ratepayer benefit in the order of $2.5 million. The question is how are the profits to be shared. This is admittedly a matter of judgment but in the circumstances the Board accepts the Company's proposed 50/50 split.

Accordingly, the Board accepts the proposed program, subject to the aforementioned provisions, as described in Appendix D of the 2007 Settlement Proposal.

RISK MANAGEMENT PROGRAM

In the Company's last year's proceeding (EB 2005-0001), the Board stated in its decision as follows:

> The question that remains is the extent to which Enbridge's risk management program is redundant or represents a useful and cost effective tool to reduce consumer price volatility in a fair and reasonable way.
>
> …
>
> No evidence has been provided that demonstrates whether the hedging activity had a material effect on the volatility experienced by customers, given the effects of QRAM, the PGVA, and equal billing programs over the same period.

and directed:

…. Enbridge to prepare for consideration in its next rates case evidence which demonstrates the extent to which the Company's hedging activities in 2003, 2004, and 2005 would have resulted in reductions in volatility for its customers, had it applied the proposed $75 action level.

Issue 3.10 in this proceeding asks: "Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?" Issue 3.13 deals with the disposition of existing deferral and variance accounts, including the Gas Supply Risk Management Program Deferral Account.

In response to these issues, the Company is seeking approval for two things:

(a) the continuation of its Risk Management Program; and

(b) closing to rate base of the expenditures incurred upgrading from an Excel spreadsheet to a database format which have been recorded in the Gas Supply Risk Management Program Deferral Account.

While the risk management program affects all customers that are on system gas who may be served under Rates 1, 6 or 10, the Company acknowledged that the objectives of the program are aimed at residential and small volume general service customers. The Company also acknowledged that it is the customers that are not on direct purchase and the customers that are not on budget billing that are most affected by the program.

The Company has an optional budget billing plan where the customer, whether direct purchase or system gas, can smooth rate fluctuations by making payments of equal amounts. The Company also has a Board-approved QRAM mechanism where commodity prices are updated quarterly to reflect more recent forecasts. The updated forecasts also form the new base for the PGVA, a mechanism for capturing the differences between forecast and actual commodity costs to the Company. Under the budget billing plan, the customer's forecast payments for a twelve month period starting in September are equalised with July being the true-up month. For August, actual use is being billed. A customer's bill is reviewed every three months and revisions to the amounts may be required to reflect the customer's natural gas usage or if there is a significant change in the reference price or both.

The Company acknowledged that if it terminated its risk management program, it would not affect its gas supply as the program is done through financial instruments only. The Company also indicated that even if it had a more frequent rate adjustment mechanism than quarterly, this may not have any impact on the price volatility that is happening in the physical market. The Company explained that any frequency of rate adjustment will have the potential to change the magnitude of the PGVA but the PGVA is driven mainly by the volatility in the forward 12-months prices.

The Company's evidence showed the impact of its Risk Management activities on the PGVA reference price from January 1, 2002 through to October 1, 2006. The

Company's evidence displays the actual PGVA reference price and what that price would have been without Risk Management activity built into it and the quarter-over-quarter change of the PGVA reference price for both the risk-managed and non risk-managed pricing scenarios. The variance of the risk-managed versus non risk-managed scenarios is calculated in absolute dollar terms per 10^3m^3. The evidence shows that, in general, risk management results in less volatility in the PGVA reference price. The quarter-over-quarter swings are muted by risk management. The largest variance is negative \$6.07 per 10^3 m^3. Generally, the volatility reduction over the period was in the \$1 to \$2 per 10^3 m^3 range.

The Company acknowledged that it did not provide the information or calculations sought by the Board in the previous decision to demonstrate whether the hedging activity had a material effect on the volatility experienced by consumers given the effect of QRAM, the PGVA and the budget billing plan. The Company explained that it would be very difficult to recreate that history given how the hedging program works with the trigger points and hedging instruments. It would be largely a theoretical exercise and the results would not be reliable.

In responding to questions whether the risk management program should be addressed as part of a pending review of the QRAM process, the Company indicated that this review is aimed at reviewing cost allocation issues to system gas and standardization of QRAM for Enbridge and Union Gas, and that the risk management issue can be assessed independently of this review.

The Company has recorded the sum of \$691,500 in the 2006 Gas Supply Risk Management Program Deferral Account ("GSRMPDA"). These amounts were incurred by the Company converting from Excel spreadsheets to a database format, as recommended by RiskAdvisory in the RP-2003-0203 proceeding. In the last main rates case, the Board chose not to close the IT capital costs in rate base as requested by the Company and, instead, found that the balance should be disposed of according to the Board's decision in this case. The Company proposed that, even if the Board directed discontinuance of the risk management program, the capital costs should be recovered from ratepayers as these costs were prudently incurred. The Company noted that RiskAdvisory's recommendations to convert the format were at no time challenged by any party and that at the time the Company began incurring these costs, it had recently been told by the Board that risk management was of value to ratepayers and would be continued.

Tom Adams, on behalf of Energy Probe, calculated the impact of the program on customer bills to be no more than one percent. His evidence also noted the $107 million losses incurred by the program in the last five years and expressed concern of the intergenerational inequities that arise from those losses. He concluded that the Company's risk management program is redundant and is therefore neither a useful nor an effective tool for reducing volatility for the residential consumer.

The Company noted that Mr. Adams' evidence only shows the impact of the risk management program on the commodity price at points in time; not the difference in the volatility the customer experiences over the quarter-over-quarter change, which in the Company's view was the Board's direction in the previous rate case. When prices are compared at the same point in time, the Company argued, it is not going to give an indication of the volatility or the extent of the price change that a customer experiences. On the other hand, the Company's evidence shows exactly that.

Positions of the Parties

The Company noted that risk management is an activity common to utilities across North America and that the Board itself noted in its Decision with Reasons in the RP-2003-0203 proceeding that only one major Canadian gas utility does not have a risk management plan. The Company's risk management activities have been the subject of two customer surveys, regular reviews by the Board and a detailed examination by a recognized expert in risk management activities, RiskAdvisory, only several years ago. The purpose of such activities and the benefits to ratepayers have not changed, and while the Company has been undertaking risk management activities for many years, the evidence in support of it is very current, beginning with the 2003 Rates Case (RP-

2002-0133). In its Decision with Reasons, the Board found that risk management activities are of value to ratepayers.

Ratepayers should not conclude they have either benefited or lost because of the risk management activities in any specific year, because when one views the net impact of such activities over time, the net impact will change from positive to negative, or vice versa, from year to year. While there will be gains and losses in each year in which risk management activities are undertaken, the net effect over time will be close to zero.

As demonstrated by the Ipsos-Reid Survey filed in the proceeding, a significant majority of ratepayers favour the Company undertaking steps to mute price volatility. The fact that the Company is regulated does not and should not reduce the need to exhibit good business practices by responding favourably to reasonable service requests by customers.

When one examines the results of risk management activities over time by looking at the percentage reduction in quarterly price changes on a quarter over quarter basis, the results are material and of value to ratepayers. The estimated $170,000 annual O&M cost associated with risk management amounts to little cost on a per customer basis. For the same reasons that industrial customers undertake similar activities to moderate commodity price volatility, so too should residential and commercial customers on system gas similarly benefit from risk management activities undertaken on their behalf collectively.

The Company cautioned that the value of risk management activities to ratepayers not be confused with the impact on the monthly amounts payable by customers that subscribe to the budget billing plan, which is simply a budgeting tool for ratepayers - it does not have any impact on the commodity price otherwise payable. Customers on the budget plan can be subject to large increases and decreases in the monthly amount payable to reflect price and consumption changes. The direct purchase customers have already eliminated commodity price volatility by agreeing to a fixed commodity price. The reason why such customers opt for the plan is not to address commodity price volatility, but for budgeting and/or the smoothing of invoice amounts over the better part of a year.

Enbridge argued that Energy Probe fails to look at volatility from one quarter to the next, and instead expresses the results of risk management as simply a percentage of the commodity price at a particular point in time.

CCC supported the continuation of Enbridge’s risk management program and proposed that a broad review of system gas pricing is the most appropriate forum to consider how best to weigh the objectives of providing meaningful pricing signals but at the same time minimizing volatility.

VECC also supported the continuation of the program and the clearing of the $691,000 deferral account as proposed by the Company and stated that any concerns about the program should be addresses in the Cost Allocation of System Gas and QRAM process generic review.

Energy Probe argued that the Company has not been able to demonstrate that its risk management program had a material effect on the price volatility experienced by customers. While the operating costs of the program are not substantial, large losses have been incurred and there is no indication that these large losses will not become even larger, giving heightened concerns for inter-generational inequities and non-price transparency. Energy Probe submitted that the program should be terminated, in an orderly fashion but noted that it is not opposed to the $691,000 expended amount to be closed to rate base.

IGUA submitted that the Board should focus on the program’s incremental value to that of the combined effects of QRAM, the PGVA, and the budget billing program. In IGUA’s view, neither the Enbridge nor Energy Probe’s evidence completely addresses the issue of incremental value. IGUA argued that the Company’s risk management program does nothing to reduce the volatility that remains inherent in the QRAM regime. IGUA noted that Enbridge’s cumulative losses because of the risk management program should prompt the Board to seriously consider directing Enbridge to cease the program.

Should the Board be reluctant to treat Enbridge differently than Union Gas, then the programs for both utilities should be reviewed on the basis of their incremental value over and above the smoothing already produced by the QRAM, the PGVA and budget billing programs in the generic QRAM proceeding contemplated in the Board's 2007-08 business plan. As for the $691,000 expended amount, IGUA argued that it should not be recovered from ratepayers since Enbridge has failed to satisfy the Board's condition that the program has value.

Schools argued that it would be in the public interest to phase out the Company's risk management program as soon as reasonably possible as it has not delivered benefits over the costs. The program has had only a limited impact on reducing volatility and there are other less costly methods of reducing volatility, such as the budget billing plan. To the extent that the program does have any impact on reducing price volatility, it mutes price signals and thus it runs counter to promoting conservation and encouraging market choices.

Board Findings

The Company and others have placed much emphasis on what they perceive is being revealed by customer surveys on the Company's risk management activities. Results of customer surveys cannot and should not be determinative of disposing of a matter. The Board's mandate is to set just and reasonable rates, which involves a balancing of many considerations. A prime consideration is cost effectiveness. It is clear that the previous Board panel decided the way that it did with the benefit of the Ipsos-Reid survey. The Board panel in that case made the decision that it did, which was to enunciate certain tests under which the Company's program should be scrutinized.

The previous Board panel concluded that no evidence had been provided that demonstrated whether the hedging activity had a material effect on the volatility experienced by customers, given the effects of QRAM, the PGVA, and equal billing programs.

The Company explained that it was not feasible to do so in this case, given the way its hedging program operates, the change in threshold levels, the complexities in attempting to reconstruct history and the questionable reliability of the ultimate results. The Board accepts this.

This leaves the other finding of the previous Board panel. Namely, the extent to which Enbridge's risk management program is redundant or represents a useful and cost effective tool to reduce consumer price volatility in a fair and reasonable way.

The Board notes the Company's concerns that the value of risk management not be confused with the impact of the budget billing plan on the monthly amounts payable by customers that subscribe to the plan. But the conclusion cannot be any other than there is little if any value for customers on the budget plan. There is no offset to bill volatility for these customers. These customers make equal payments for ten months of the year, and they eventually pay the actual costs. Adjustments prior to true-up may be required from time to time but these can also be because of factors other than commodity price changes. The existence of a risk management program is not really that relevant or of value for those customers.

This leaves the system customers who are not on budget billing. The volatility reduction over the last five years was in the \$1 to \$2 per 10^3m^3 range, which is fairly small relative to the prevailing PGVA reference price. The impact on the total customer bill impact in percentage terms is very marginal. The Company's argument that the annual costs associated with the program are small is not persuasive. This can be said about many other program and activities costs. The relative small size of costs involved in a program should be only one consideration. Other considerations are also important.

The Board notes from the evidence that for the period January 2002 to October 2006, the impact of the program was an accumulated net loss of \$107.3 million. In 2006, the loss was \$110.5 million. For 2007, at the time of the hearing the position of the account was a loss of about \$16 million. Clearly, in the most recent five years at least, the program was not an effective enterprise. It came at a high cost to the consumer. It is possible that the losses may be reversed in the future. It is however questionable whether this is necessarily a zero-sum game. To have a zero-sum result from the current position as a starting point, gas prices going forward have to be assumed as trending upward, not just gyrating around their current level, and that there is no cost in engaging in hedging.

Further, losses or gains as a result of the program do have intergenerational impacts. These impacts can be significant at times. The $110 million loss in 2006 for example is a cost that will need to be recovered by customers who may not have been customers during the time the loss had occurred. Although inter-generational impacts cannot be avoided in every circumstance, they should be mitigated or avoided when it is possible and reasonable to do so.

The Company's and Energy Probe's evidence have satisfied the Board that the rate smoothing attributable to the Company's risk management program for the remaining system customers not on equal billing is marginal at best. While the annual costs of operating the program are of lesser concern to the Board, the inter-generational impacts in light of the substantial losses are of significant concern.

Given the program's minimal impact on the other system customers not currently on equal billing, the impact will likely be unnoticed by these customers. For these customers, the option is still available to take advantage of the Company's equal billing plan if they so choose.

For all of the above reasons, the Board directs the Company to cease its risk management program as soon as practical.

In reaching this conclusion, the Board has considered the arguments that Union has an approved risk management program. This panel of the Board is mindful that, to the extent possible and practical, Board regulatory policy should be consistent. However, it would not be appropriate on the basis of the evidence adduced in this proceeding for the Board to allow continuation of Enbridge's risk management program. It would similarly not be appropriate to defer this matter to the future Cost Allocation of System Gas and QRAM process generic review without ruling on the matter on the evidence adduced in this proceeding. In that this decision may have implications for Union in a future rates case, it would be up to parties to raise the issue in a future Union proceeding.

With respect to the $691,500 recorded in the 2006 Gas Supply Risk Management Program Deferral Account ("GSRMPDA"), the Board is mindful of the Company's concern of the longer term problems for decision making, on IT projects specifically, if the test is something other than the prudence of undertaking these projects based on the information available to the Company at that time. Given the history of endorsement of the Company's risk management program by intervenors and the Board, the Company's decision to proceed with the implementation of the recommendation by its consultant is certainly understandable. In these circumstances, the Board will allow recovery of the costs recorded in the 2006 GSRMPDA. The 2007 draft rate order is to include the full disposition of this account in 2007 and Enbridge is to ensure there are no Risk Management related costs included in 2007 rate base. The Board considers appropriate that this amount will be recovered from system gas customers.

DEFERRAL AND VARIANCE ACCOUNTS

Issue 3.12 deals with the establishment of 2007 deferral and variance accounts. All except one of requested deferral and variance accounts were the subject of the Settlement Proposal accepted by the Board. With respect to Company's proposals regarding Customer Care and Open Bill Access related deferral accounts, the parties indicated that these would be addressed under Issues 7.2-7.4 and 7.5 respectively. In this regard, the establishment of a 2007 Open Bill Access Services Deferral Account remained unsettled as part of the larger Open Bill Access-Inserts issue and is addressed in the Open Bill Access Chapter of this Decision.

In the EB-2006-0021 Natural Gas Demand Side Management Generic Decision with Reasons, issued August 25, 2006, the Board ordered the creation of a deferral account to record any carbon dioxide offset credits that the Company might earn. The Company included this deferral account (the 2007 Carbon Dioxide Offset Credit Deferral Account) in this proceeding, which was not an issue but was filed for completeness.

Disposition of Existing Accounts

Issue 3.13 relates to the disposition of existing deferral and variance accounts. In the Settlement Proposal, there was an agreement to settle a number of existing deferral and variance accounts and to defer consideration of the clearance of others to a future date. The Company proposes to clear the balance of all settled accounts, adjusted to reflect the Board's decision in respect of accounts reviewed and tested during the hearing, together with the outstanding balance in the 2006 PGVA.

There was no agreement reached with respect to the disposition of six deferral accounts. One of these accounts, the 2006 Gas Supply Risk Management Program Deferral Account, was dealt with earlier in this Decision under Issue 3.10 "Risk Management Program". The following five deferral accounts will be discussed below:

2006 Electric Program Earnings Sharing Deferral Account (2006 EPESDA)

2006 Unbundled Rate Implementation Cost Deferral Account (2006 URICDA)

2006 Alliance Vector Appeal Cost Deferral Account (2006 AVACDA)

2005 and 2006 Gas Distribution Access Rule Costs Deferral Accounts (GDARCDA)

2006 Electric Program Earnings Sharing Deferral Account (EPESDA)

The Company proposes the disposition of $175,100 which amount has been recorded in this account as a credit to ratepayers. This represents 50% of the net revenue of the Electric Program earnings after deducting program costs. This account and the 50/50 sharing were approved by the Board in the EB-2005-0001 proceeding in its Partial Decision with Reasons, dated December 22, 2005.

CCC expressed concern with the "lack of evidence" provided in this case to support the calculation of the $1.45 million in gross revenue and the costs in material, service costs, and internal costs. CCC stated that while it accepts the clearance of this account as proposed, in the future the Company should provide detailed evidence in support of the calculation of net revenue and should be required to determine net revenue on a fully allocated cost basis. IGUA stated that it supports CCC's position with respect to this matter.

The Board notes that no party opposed the clearance of the balance on this account as proposed by the Company. The Board also notes that the DSM Generic Decision (EB-2006-0021) directed that, from 2007 onward, the gas utilities shall allocate their internal costs on a fully costed basis. The balance the Company seeks to dispose of relates to 2006. In any event, the Board accepts the Company's submission that, as this activity is new for the Company, the internal costs for 2007 will be minimal. The Board approves the clearance of the balance recorded in this account as proposed by the Company.

2006 Unbundled Rate Implementation Cost Deferral Account (URICDA)

The Company developed unbundled rates and services for power generation and large volume customers as part of the NGEIR proceeding, which concluded in August 2006. In that proceeding, all parties agreed that the Company should be kept whole with respect to the implementation and introduction of unbundled rates and services. Parties to the NGEIR Settlement Proposal agreed to support the establishment of the 2006 URICDA and to support the recovery by the Company of prudently incurred costs recorded in the account.

The amount recorded in this account which the Company proposes to be cleared to rates is $480,500. This is the cost to implement the new unbundled rates and services, including design, development and implementation of a manual tracking tool, training, communication, and customer education costs, as well as legal and staffing costs.

As part of the NGEIR proceeding, the Board was asked to consider a threshold issue about which customers should be responsible for the unbundled rates implementation of costs. In an oral decision delivered July 14, 2006, the Board found that these costs should be recovered from large volume customers. Accordingly, the Company proposed to recover these costs from all large volume customers, bundled or unbundled, based on customer numbers.

IGUA stated that it supports the Company's proposal to allocate the amount to the large volume rate classes using customer numbers as the allocator. However, IGUA noted that it reserves its rights with respect to the manner in which any credit balance accumulated in this account is cleared to rate classes in the future and reserves its right to seek a re-balancing of Rate 115 and the baseline from which this account will operate, in the event that Transalta continues to take service on Rate 115.

The Board notes that no party objected to the clearance of the balance in this account as proposed by the Company. The Board also finds the Company's proposal reasonable and approves it.

2006 Alliance Vector Appeal Cost Deferral Account (AVACDA)

In RP 2002-0032, the Board ruled that Enbridge could not recover some $11 million in costs arising from a contract to transport gas on the Alliance/Vector pipeline system. Enbridge appealed that ruling to the Divisional Court, which found that the Board had erred. The Board sought and was granted leave to appeal the decision by the Divisional Court to the Ontario Court of Appeal, which found that the Divisional Court had erred. Enbridge sought but was denied leave to appeal to the Supreme Court of Canada.

The Company has recorded costs of $529,000 plus interest in this Board-approved account. All of the costs, according to the Company, are external legal fees and disbursements associated with the Company's actions on the Board's application for leave to appeal to the Court of Appeal and the Company's application for leave to appeal to the Supreme Court, and none of the claimed costs are related to its own appeal to the Divisional Court.

During the 2006 rate case, the Company had planned to record relevant costs and seek approval for clearing these costs to rates by means of the Ontario Hearing Costs Variance Account. The Board, however, in its 2006 Decision, directed the Company to apply for a new deferral account specifically to capture the costs associated with the Alliance Vector appeal. The Company subsequently requested and received approval, under docket EB-2006-0144, to establish the account. The Board in its 2006 rates decision (EB-2005-0001) commented about some of the considerations that should apply when it is asked to consider disposition of costs relating to an appeal of a Board decision. Specifically, the Board stated:

> The rate structure in Ontario is predicated on a just and reasonable standard. Where a utility acting in good faith regards a Board decision to be unsound, it should be open to bring a Judicial

> Review action, and to have prospect of recovery of the associated costs.

In addition, the Board also had the following to say in that decision about determining the prudence of expenditures for appeals:

> In our view, the question of the prudence of the expenditure is not dependent on the success or failure of the review pursued by the Company; nor is the primary consideration whether the aspect appealed from inures to the benefit of the shareholder or the ratepayer. The determination of the prudence of the expenditure will turn on the reasonableness of the grounds for the review, the reasonableness of the costs incurred, including the relationship of the costs incurred to the likely outcome (which includes such intangibles as precedent, clarification of the law and corporate reputation), and the extent to which the Company can show that it prosecuted its case diligently and efficiently.

The Company submits that it clearly meets all tests which the Board stated are appropriate during its consideration of costs incurred by the Company on an appeal of a Board decision.

First, in respect of the Alliance Vector Pipeline disallowance by the Board, the amount was significant, being approximately $11 million. The appeal did not involve a frivolous amount.

Second, the Company was successful on its appeal to the Divisional Court and that this is clear evidence of the reasonableness of it undertaking the appeal. It also confirms that the Company acted in good faith launching the appeal. While the Company agrees with the Board that the prudence of appeal expenditures is not dependent on the success or failure of the review, the fact that an independent judicial body agreed with the Company, is irrefutable proof of the reasonableness of the grounds for the review and hence the appropriateness of it launching the appeal.

Third, as to whether the costs incurred were reasonable, the Company is not seeking to recover any of the costs it incurred associated with the original appeal to the Divisional Court.

Fourth, there can be no question about the appropriateness of the Company recording the costs which it did in this deferral account. In its EB-2005-0001 Decision with Reasons, the Board specifically stated that the Company should apply for a new deferral account to capture the costs associated with the Judicial Review process at Divisional Court and any appeal proceedings thereafter.

Fifth, all of the amounts recorded in this account relate to legal fees and disbursements invoiced by the Company's counsel on the appeal, Fraser Milner Casgrain, who were also counsel on the original Divisional Court appeal. Accordingly, there were no costs incurred which would be associated with retaining and educating new counsel.

Sixth, all of the legal bills that were received would have been directed through the Company's Associate General Counsel, and then they were subsequently reviewed to determine that the hours and dates spent were sufficient in the context of the proceedings. Counsel on the appeal, Fraser Milner Casgrain, were in fact the same counsel that acted for the Company in the proceedings before the Board where the Alliance Vector costs were disallowed. None of the costs associated with Fraser Milner Casgain's representation of the Company at that Board proceeding were disallowed.

Seventh, the OEB's costs for its leave to appeal the Divisional Court decision and the subsequent appeal of the Divisional Court decision are being recovered from Ontario ratepayers through the OEB's assessment authority. It only seems fair and reasonable that the Company also recover its costs from ratepayers for responding to the proceedings initiated by the Board.

CCC argued that the Company should not be allowed to recover any of the $529,000 amount claimed. In the alternative, it should recover no more than $30,000. In support of this alternative amount, CCC noted that the Board's principles were enunciated before Enbridge's application for leave to the Supreme Court and therefore these principles do not apply. Rather, section 40 of the *Supreme Court Act* specifies the criteria that the Supreme Court of Canada applies whether leave will be granted and Enbridge did not meet the Court's criteria. The Board must decide on the reasonableness of Enbridge's costs with that in mind, especially since Enbridge did not file any evidence so that the Board would be able to judge the merits of that application. Moreover, the $82,000 in costs associated with that application for appeal "seems grossly disproportionate". With respect to the $445,000 in claimed costs for responding to the Board's application for leave to appeal to the Ontario Court of Appeal and the appeal itself, CCC termed the claim "grotesque".

IGUA and VECC noted that they support CCC's position with respect to this matter.

Schools submitted that the Company's evidence is insufficient to demonstrate the reasonableness of the costs claimed, which the Company was required to do. Even allowing for preparation time, $529,000 (before interest) for a matter that took one day of argument at the Court of Appeal is excessive.

The Board does not question the Company's proposal to recover costs associated with its participation to the Ontario Court of Appeal and its application to the Supreme Court of Canada. Neither does the Board question the existence of records to support this claim. It is not expected that the Company file such detail as part of its pre-filed evidence. While the onus is on the utility to prove its case, it was open to the parties to ask for supplementary information through the interrogatory process or during the hearing when the issue was canvassed. Parties did not develop that additional record. It is not reasonable to now fault the Company for an "insufficient" record. On the record before it, the Board finds it appropriate that the recorded balance in this account should be recovered by the Company, as proposed.

2005 and 2006 Gas Distribution Access Rule Costs Deferral Accounts (GDARCDA)

The amounts recorded for the 2005 and 2006 GDARCDA are $435,200 and $7,985,400, respectively. These amounts are to be capitalized. The amounts recorded in these accounts relate to the costs incurred by the Company to ensure that it is GDAR compliant.

The Board and all participating parties have been aware over the years that the Company would incur significant costs to meet the requirements of GDAR. It has only been over the course of the last year where enough detail has been driven out to the point where the Company could start to look at how it would have to re-engineer its business processes and modify its computer systems to accommodate the rule.

The project has been governed by a Steering Committee, in addition to an external risk manager, and a senior representative from both the Company's IT and Regulatory groups.

There has been a Project Manager in place throughout who reports to the Steering Committee and who also manages external resources working on the project. The Company has had a detailed project plan in place, which includes work plans and project milestones which form the basis of the project's budget.

The costs recorded in the 2006 deferral account plus the costs that the Company will incur in 2007 to be compliant by June 1st, in total will be about $1.7 million lower than the initial estimates provided.

CCC supported the clearance of the accounts, on the assumption that the costs are entirely related to Service Transaction Requests, but noted that this support is in no way an acceptance of the reasonableness of the GDAR costs that will be incurred in the future.

IGUA noted that it supports CCC's position with respect to this matter.

VECC stated that it has no reason to dispute the prudence of the costs incurred in this account. VECC requested that the Board require the inclusion of a representative of small volume customers in the remaining GDAR implementation stages as the small volume customers were not directly engaged in the process, though they will bear the cost consequences.

On the basis of the evidence, the Board has no reason to doubt that the reported balances are not related to Service Transaction Requests and that they are not reasonable. The Board accepts the disposition of the reported balances as proposed by the Company.

With respect to VECC's request for inclusion of a representative of small volume customers in the remaining GDAR process, the Board notes that GDAR is an independent initiative from this proceeding and VECC may make this request in that process.

CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 4.2 was whether the Company's proposed costs for its debt and preference share components of its capital structure appropriate. No party took issue with the Company's evidence, nor does the Board.

This section therefore addresses the remaining issue related to capital. Specifically, Issue 4.3 read "Is the proposal to change the equity component of the deemed capital structure from 35% to 38% appropriate?" There was no settlement of this issue.

The Company' evidence is that it has suffered a dramatic decline in its financial strength. As a result, Enbridge's ability to raise new long term debt has been constrained and there is a real risk of a further downgrade in the Company's credit rating. An increase in its common equity ratio from 35% to 38% is necessary to restore the Company's financial integrity to a level that will allow it to sustain access to long term capital on reasonable terms. An increase in the equity thickness to 38% is also warranted by reason of higher business risks now faced by Enbridge. This latter evidence was given on behalf of Enbridge by Paul Carpenter of the Brattle Group.

Enbridge attributed the erosion in its financial strength to a steady decline in the allowed ROE that has outpaced the effect of declining interest rates on the Company's financing costs. Long term debt is issued at fixed rates for fixed terms and the rates payable on this embedded debt do not change as interest rates decline and the ROE goes down. As ROE declines, and the cost of long term debt remains fixed until debt maturities occur, the Company's ability to cover the interest on the debt is limited.

A measure of a company's financial strength is the Earnings Before Interest and Taxes (EBIT) interest coverage the ratio which is the quotient of the company's earnings divided by its interest expense. Enbridge noted that lower interest rates lower the ROE immediately but it takes time for the interest expense element of the Company's interest coverage ratio to decrease as interest rates decline, because Enbridge cannot refinance all of its long term debt in every year. The result is a lower EBIT coverage ratio which diminishes the Company's ability to issue new debt.

According to the Company, its weather-normalized EBIT interest coverage declined from a ratio of 2.38 in 1993 to 2.10 in 2006. Enbridge's margin above 2.0 times coverage for each of the years from 1993 to 2006 declined from $48.0 million in 1993 to $16.8 million in 2006.

Specifically, the Company noted that its existing trust indenture prohibits the issuance of new term debt if Enbridge's actual legal entity EBIT interest coverage ratio for any consecutive 12 month period out of the last 23 months does not exceed 2.0 times. In order for Enbridge to stay in compliance with the financial covenants in the trust indenture, the margins above normalized utility EBIT 2.0 times coverage must allow room to accommodate the effect on the Company's financial results of unexpected swings in the weather. EBIT margin above 2.0 times interest coverage had declined to $16.8 million by 2006. During the period since 1993, the average annual impact of weather on the utility's EBIT has been $35.0 million. The margin above 2.0 times interest coverage of $16.8 million is significantly less than what the Company needs to accommodate an average swing in the weather.

Enbridge testified that it must maintain a normalized allowed utility EBIT interest coverage ratio of at least 2.2. The requested equity ratio of 38.0% marginally achieves this minimum target. Given the magnitude of volatility in its earnings, the Company noted that even with 38% equity thickness and the minimum coverage at 2.2 on a weather-normalized basis, there is no assurance that Enbridge will always meet the new debt issuance test.

The Company indicated that, because of the considerably warmer than normal weather it experienced in 2006, it would not be able to meet the interest coverage test for any 12 month period that includes the period January-March 2006 to enable it to issue new debt. Actual weather in the first quarter of 2006 was considerably warmer than forecast. The warmer weather in the first quarter of 2006 alone reduced Enbridge's EBIT by

$33.3 million and the negative impact on its earnings because of weather was $57.7 million in impact for the full 2006 year.

The impact of a lower ROE in 2006 combined with actual results for January 2006 to March 2006 caused a significant decline in the actual interest coverage ratio, such that, as of January 2007, the ratio is about 1.85 times to 1.95 times depending on the 12 month period chosen from the previous 23 months. The Company noted that its ability to meet the new debt issuance test through 2007 and beyond will depend on the equity thickness allowed by the Board in this case and actual operating results for 2007, including any weather variances.

It is Enbridge's judgment that the ultimate costs to the ratepayer will almost certainly be higher if the Company's credit quality is allowed to decline further. Costs will rise due to constraints on accessing the long term debt as there is a risk for credit rating downgrades leading to suboptimal financing options.

Enbridge's evidence was supplemented by the evidence of Paul Carpenter of the Brattle Group. Dr. Carpenter provided evidence about changes in business risk that have occurred since 1993, when the appropriate level of equity thickness for Enbridge was last considered by the Board. Dr. Carpenter contends that equity investors would consider investment in Enbridge to be more risky than it was in 1993 because of a) changes in the commodity market for natural gas, b) increased risk of bypass, c) new gas-fired generation, and d) uncertainty as to the future rate regulation framework. Dr. Carpenter's remedy is also an increase in the common equity thickness but from the Company's business risk perspective, independent from the credit quality considerations advanced by the Company.

Dr. Booth, on behalf of CCC, IGUA and VECC, testified that Enbridge's current 35% allowed common equity is reasonable, if not generous. In support of that conclusion, Dr. Booth testified that Enbridge's short-term business risk is low and lower than that of Union Gas whose common equity thickness was negotiated at 36%. Furthermore, Enbridge's credit ratings have been quite stable, placing the Company among the premium group of regulated utilities in Canada.

Enbridge provided comparisons of its currently approved equity level to the equity levels in other Canadian jurisdictions and noted that it is apparent that Enbridge's equity ratio has fallen out of line during a period of years when the appropriate level of equity for the Company has not been considered by this Board, but equity levels for other Canadian utilities have been increasing.

Enbridge noted that Professor Booth's view of appropriate equity levels is not shared by Canadian regulators and is not reflective of what actually happens in the Canadian capital markets. According to Enbridge, there is clear trend in regulatory decisions towards higher levels of equity for Canadian regulated utilities. Professor Booth's views about debt/equity ratios of Canadian regulated utilities run counter to this trend and his recommendations are not aligned with what is actually happening in Canadian capital markets.

Positions of the Parties

Board Staff noted the testimony by the Company's witness that Enbridge's business risk is "pretty similar" to that of Union Gas' and that Union Gas' common equity was settled at 36%. On this basis, and on the basis that the Board has decided that a consistent debt-equity capital structure be implemented among electricity distributors, Board Staff stated that a common approach may be merited for the gas utilities and that a 36% common equity for Enbridge may be warranted.

Union Gas submitted that the OEB must consider capital structure in the context of well settled principles governing return on investment to equity holders. This includes a consideration of comparable risk, ensuring financial integrity and the attraction of capital on reasonable terms. Business risks have increased for utilities in Canada and interest coverage ratios are barring Ontario utilities from access to capital markets at a time when infrastructure investment is as important as it has ever been. Union Gas also noted that there has been a trend to increased equity thickness awarded to energy utilities across Canada.

CCC submitted that Enbridge has not demonstrated that it requires an equity component of 38%. CCC argued that Enbridge has not demonstrated that either its business risk or its regulatory risk has increased. CCC noted Dr. Booth's evidence that Enbridge's inability to access debt in the form of unsecured Medium Term Notes (MTN), is only temporary. It has been the result of the combination of warmer weather and decline in interest rates which affect return on equity pursuant to the Board's adjustment formula. As existing debt issues mature and are replaced with new ones at current interest rates, Enbridge's interest coverage ratio will naturally increase. It would not make sense to implement a longer term costly solution to address a temporary problem. CCC submitted that Enbridge has not demonstrated that its credit ratings are in jeopardy. CCC also submitted that Enbridge has effectively put itself into this temporary situation by flowing amounts to its parent during 2006 beyond what was approved by the Board. CCC noted that Union Gas has an equity level of 36% and that Enbridge's own witness, Dr. Carpenter, acknowledged that Union Gas is riskier than Enbridge. CCC noted that while it is acceptable for the Board to consider whether or not Ontario distributors should be subject to weather risk, this was not on the issues list in this proceeding. Had this been the case, parties, including Union Gas, may have filed evidence. It would be premature for the Board to make this determination in this case without the benefit of an appropriate forum for this issue to be aired.

IGUA argued that Enbridge's business risks have always been and remain low. Any recent changes in business risks facing Enbridge are immaterial and do not justify an equity ratio greater than 35%. IGUA argued that an equity ratio greater than 35% cannot be justified by comparing Enbridge to other utilities. Regulatory decisions of other tribunals do not assist Enbridge in satisfying the threshold requirement of objective and independent evidence that a material change in risk has occurred. Existence of weather risk cannot prompt an increase in Enbridge's equity ratio. The regulatory tools which should be used to respond to the weather risks Enbridge faces are the rate design measures and/or the removal of the weather risk from the Company through a deferral account as it is done by the British Columbia Public Utilities Commission. However, any consideration by the Board of a weather adjustment mechanism should take place in the context of a generic proceeding. With respect to

Enbridge's claims regarding the challenges in interest coverage and access to debt capital, IGUA argued that this is only temporary and will disappear as the Company's long term debt issues mature. IGUA termed Enbridge's proposal as a "base year stuffing" measure before the long-term incentive regulation is implemented. IGUA argued that Enbridge's actual normalized EBIT interest coverage ratio for the "stand alone" utility is more than adequate. IGUA particularly noted that the exclusion from normalized actual earnings of the sums paid by Enbridge to its parent and affiliates in excess of Board-approved amounts.

Energy Probe supported IGUA's arguments. It further noted that the Company is far from facing a crisis. The Company's proposal is in effect a request for costly insurance, to the tune of $9.5 million annually, which does not represent the least overall cost solution.

VECC submitted that Enbridge's problem of access to the MTN market is temporary and should be addressed by short-term solutions that provide access to needed capital until existing debt is retired. The best and least cost solutions according to VECC are either using commercial paper swapped into medium term debt or a medium term preferred share issue. Either one of these solutions would allow Enbridge to access capital on reasonable terms until its high coupon debt gets refunded over the next few years. Since 2008 is likely to be the first year of incentive regulation, establishment of a deferral account would allow Enbridge the opportunity to recover any prudently incurred incremental costs of maintaining access to the MTN market. In VECC's view, Board Staff's regulatory symmetry with Union Gas is not appropriate, since it does not take into account the fact that Enbridge has lower business risk than Union Gas, or that Union Gas' equity was the result of a negotiated settlement.

Board Findings

The Company's proposal for a thicker common equity in the deemed capital structure is grounded on business and financial risk considerations as well as its deemed common equity has fallen out of line with other Canadian utilities.

While the Board is of the view that Enbridge has presented credible evidence of a trend among Canadian regulators in finding thicker common equity for utilities, the Board does not generally find a comparison of Enbridge's common equity ratio with those in other jurisdictions to be necessarily determinative of the issue. An applicant must still satisfy the threshold requirement of independent evidence that material changes have occurred to justify a thicker common equity. Moreover, the hazard in doing so is that it engages issues of oversimplification and circularity, which downgrade the specificity that is required to make decisions pertaining to a particular utility. With those caveats, the Board nevertheless is mindful of the increasing trend and has factored this in its deliberations.

There is some value in considering evidence on the relative risk profile of the two large Ontario gas utilities. While Union's current 36% common equity was the result of a negotiated settlement, Enbridge's proposal for a 38% common equity level is materially higher than Union's, which is not consistent with the relative business risk profile of the two utilities. In fact, there was no dispute that Enbridge is a lower risk utility than Union Gas.

The Company claims that its business risk has increased over the last 10 to 15 years on several fronts. These are addressed below.

The Board agrees with parties who argued that the regulatory and legislative risks which Enbridge currently faces are not greater than they were last year or in prior years, at least not materially greater.

With respect to the risk of bypass noted by the Company, the Board is of the view that the Company has under-estimated the risk mitigation through the development and approval for rate options to specifically address the need of gas fired generators and mitigate any potential for bypass risk.

With respect to the claim by Enbridge that incentive regulation could lead to increased regulatory risk, Enbridge has operated under a performance based mechanism before. Moreover, the tenet behind an incentive regime is that the utility can reap the benefits of newly found efficiencies and it is only upon rebasing that these efficiencies will be shared with or passed on to ratepayers. From these perspectives, an incentive rate reqime is not necessarily an arrangement that negatively affects the risk of the utility.

From the market reports that were filed in the proceeding, there is no evidence on balance that Enbridge no longer enjoys a reasonably stable legislative and regulatory environment.

Even if there was some recognition of increased business risk in the totality of the Company's arguments, this must be weighed against other positive considerations. For example, the Company's evidence indicates that customer growth continues to be strong and natural gas remains the predominant fuel of choice in Enbridge's franchise area. Enbridge's customer base is consistently growing year after year. The Board does not see this as indicative of increased business risk.

In the result, the Board finds that the evidence presented by Enbridge does not warrant an increase in the common equity thickness to 38% on account of increased business risk, but the evidence on the trend of common equity thickness suggests that the 35% level in existence since 1993 should be considered as a floor.

This leaves the Company's proposal to also be evaluated on the basis of its claimed inability to raise capital, at least on reasonable terms.

The Board accepts that decreases in interest rates in 2006 have impacted the Company's EBIT adversely as there is a lag between the reduction in ROE and reductions in the total debt interest liability. The warmer than normal weather in 2006 contributed to the impact on EBIT. To worsen matters, the Company has paid out considerably more to its affiliates than what was reflected in the Board's 2006 revenue requirement decision. Whether or not the Company will be able to raise long term debt in the 2007 test year will very much depend on weather and its overall performance going forward.

The Board accepts that there may not be a practical way to circumvent the interest rate covenants in the current trust indenture. To alter these covenants would require agreement by current debt holders and this will likely come at a cost. To be clear, the Company is not suggesting that this would be a reasonable remedy. It is unfortunate that these covenants pose such a high restriction. The Board notes that the Company is considering ways by which the existing covenants may be replaced in the longer run. The Board encourages the Company to pursue this initiative.

The Board agrees with the many intervenors who argued that the problem is or may be temporary. On the assumption of a continuing low interest rate environment, as debt matures and is replaced the lower interest charges would provide some relief. If interest rates increase, the relief may be quicker. Relief may well even come from weather.

In any event, like many intervenors the Board is not convinced that the Company's proposed remedy to what is or may be a temporary problem represents the least cost solution. The common equity component of Enbridge's capital structure is and should be a matter that is reviewed infrequently. The Company's proposal to increase the common equity thickness from 35% to 38% carries an annual cost of about $10 million to ratepayers. In view of that substantial cost, the Board must consider other remedies.

In consideration of all of the above, and on balance, the Board finds an increase in the common equity thickness from 35% to 36% to be reasonable. While this finding should alleviate somewhat the financial pressure currently experienced by the Company, it alone might not fully address the immediacy of the problem, if the problem continues indeed to exist. The Company therefore might need to engage in financing alternatives other than issuing of long term debt in the shorter term. This may involve a number of market instruments that are available to the Company, if indeed the Company cannot issue long term debt when it needs it. The Company must also be more wary of the impact of excessive payments to its affiliates on EBIT.

The Company's evidence was that, in the period 1993 to 2006, the Company lost $107 million in EBIT due to warmer-than-forecast weather and that the average impact of weather in either direction on EBIT was $35 million, which is two times more than the $16.8 million currently reflected in rates according to the Company's evidence. The

Board is of the view that, given the large influence of weather on EBIT, this risk may need to be removed from the utility.

The Board recognizes that a move to removing weather risk from the Company is a decision that has implications for all regulated gas utilities regulated by the Board, and perhaps for electricity utilities as well. The Board considers this to be worthy of evaluation in the near future.

REVENUE TO COST RATIOS

The revenue to cost ratio compares the forecast recovery of revenues from each rate class, derived through the rate design process, to the allocation of forecast costs for each rate class, arrived at through the cost allocation process. A revenue to cost ratio for a rate class of unity means that the rate class is forecast to recover all of the allocated costs to that class.

The Company's pre-filed evidence set out the manner in which it initially proposed to allocate the proposed revenue requirement among customer classes. Issue 6.2 reads:

> Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable?

Parties agreed on matters pertaining to the adjustments to the monthly customer charges and variable charges. The unresolved aspect of Issue 6.2 is described in the Settlement Proposal as follows:

> There is no agreement about the Company's proposal to allocate revenue requirement between customer classes. Some parties are concerned that the allocation of the 2007 revenue deficiency as proposed in the Company's evidence results in the collection of revenues greater than allocated costs from Rate 1 and Rate 6 customers based on the Company's filed Revenue to Cost ratios of 1.02 and 1.01 for these rate classes. These parties wish to explore the proposed 2007 revenue requirement allocation in light of the evidence and interrogatory responses on this issue. Other parties support the Company's revenue deficiency allocation and will oppose changes to it.

Appendix B to the Settlement Proposal sets out the Company's proposal for the recovery of the test year revenue requirement with assumed revenue deficiencies of $26 million and $82 million, which reflect the minimum and maximum revenue deficiencies that could result from the final Board decision in this case. Appendix B also sets out the revenue to cost ratios that would result for each rate class. In both scenarios, the revenue to cost ratios proposed by the Company for Rate 1 will be 1.01, which is the same as the Board approved in 2006. The revenue to cost ratios proposed for all other rates are 1.01 or less.

Appendix B also sets out the dollar amount of any over or under contribution by each rate class, relative to the costs allocated to that rate class. A portion of the over and under contribution for most rate classes relates to the phase-in of the allocation of upstream transportation costs on a volumetric basis (referred to as the phase-in of TCPL tolls). This phase-in, which was approved in the Company's 2005 rate case (EB-2003-0203), was to be completed over four years, so that the rate increase impact on large volume customers would not be too large in any one year. A corresponding impact of the phase-in is that associated over-contributions from Rates 1 and 6 have remained in place, at least in part, for four years while the under-contributions from large volume customers were phased out. The phase-in will be completed as of October 1, 2007. From and after that time, the actual amount of over or under-contribution for each rate class will no longer include any adjustment. All things being equal, the forecast revenue to cost ratios for Rates 1 and 6 will have decreased as the impact of the upstream transportation cost allocation adjustment is fully phased in.

The Company provided an illustrative example of how other rate classes would be impacted in the test year if $5 million of revenue requirement were shifted away from Rate 1 and recovered instead from the large volume rate classes. The effect of such a shift would be that, on a prospective basis from October 1, 2007, the rate increase for Rate 100 would move from 1.9% to 3.6%, the rate increase for Rate 145 would move from 1.6% to 8.0% and the rate increase for Rate 170 would move from 1.8% to 8.0%.

Whatever the ultimate revenue deficiency that the Board determines in this case, the Company has indicated that it will maintain revenue to cost ratios, and over/under contribution amounts by rate class, at approximately the same level as set out in Appendix B to the Settlement Proposal. The Company has also indicated that it will file, along with the draft final rate order in this case, a narrative explanation of the steps taken and adjustments made to arrive at final rates, and corresponding revenue to cost ratios.

Positions of the Parties

The Company asserts that its proposal is a fair and appropriate approach to the recovery of the revenue requirement from all rate classes. The approach is consistent with that taken and approved by the Board in previous years, where the revenue to cost ratio for Rate 1 has also been 1.01.

While the Company attempts to set revenue to cost ratios as close to 1 as possible, it also must take account of other rate design objectives. These objectives include rate stability, market conditions, maintaining competitive position, market acceptance, rate class characteristics and rate impacts on other rate classes. The Company also takes account of the revenue to cost ratios for each rate class from previous years and seeks to maintain similar ratios, on the assumption that the Board approved those ratios in previous years, and in order to avoid large rate swings in some rate classes which have corresponding impacts on others. While the Company seeks to keep revenue to cost ratios close to 1, the actual ratios are typically slightly different from 1, but within a reasonable band of tolerance so that there is no undue over or under collection from any particular rate class. The Company believes that it is important to retain some degree of flexibility with respect to revenue to cost ratios, so that the variety of applicable rate design objectives can be addressed. If the Company were required to maintain prescribed revenue to cost ratios, this flexibility would be lost. Moreover, a requirement to meet specified revenue to cost ratios could be very difficult to implement and maintain over time and, in some cases, may not be feasible.

If $5 million was shifted away from Rate 1, the level of rate increase to some rate classes would be less appropriate than the approach the Company advocates, particularly in the case for customers on interruptible Rates 145 and 170 who have dual fuel capability. In the event of large increases to those rates, affected customers may switch away from gas altogether, leaving other customers worse off as a result.

IGUA, Transalta and OAPPA supported the Company's proposed revenue to cost ratios as reasonable and falling within tolerable limits.

CCC noted Enbridge's testimony that it will be more explicit that it has been in the past regarding the determination of final rates as part of the Rate Order and in CCC's view this would be helpful.

VECC expressed concern with the proposal to maintain a revenue–to-cost ratio greater than one for Rate 1 customers in the test year. If the proposal is accepted and not corrected prior to setting base rates for a multi-year incentive regulation program, this over-contribution would be embedded for the duration of such scheme.

Board Findings

The Board notes that the proposed revenue to cost ratio for Rate 1 is actually 1.006, which has been rounded to 1.01. The Board considers this to be within a reasonable band of tolerance given the many other considerations and factors that enter into striking rates for each class, which they were enumerated by the Company. Requiring the Company to maintain strict 1.0 revenue to cost ratios for each class will remove the flexibility that may be needed to accommodate those other considerations and factors.

VECC's concern is that the settled revenue to cost ratio for Rate 1 in this proceeding will be fixed for the next six years under planned incentive regulation. The Board agrees with the Company that the cost drivers that will play into revenue to cost ratios over the next six years cannot be known now and that there is a pending rate proceeding to deal with rate-setting issues under incentive regulation.

The Board therefore accepts the Company's proposed revenue to cost ratios, and these shall be used to calculate proposed rates reflecting the final revenue requirement reflecting the Board's findings in this proceeding.

The Board notes the Company's commitment, as stated in its argument-in-chief , that it will file, along with the draft final rate order in this case, a narrative explanation of the steps taken and adjustments made to arrive at final rates, and corresponding revenue to cost ratios.

RATE IMPLEMENTATION

In regard to Issue 9.1 (How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?), the Company is seeking approval for the full recovery in rates during the 2007 test year of the full amount of revenue deficiency awarded by the Board in its final decision in this case. The Settlement Proposal in respect to this issue provided that:

> All parties agree that for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. GEC's and Pollution Probe's agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1.

and parties, except for Schools, agreed that:

> …..the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. Parties agree with and support the Company's proposal to recover the full $26.0 million through (i) increased annualized rates for the remainder of the test year; and (ii) the use of a rate rider over the nine remaining months of the test year to recover the remaining balance of the $26.0 million. Intervenors agree that no issue or objection will be raised around whether any part of this $26.0 million is unrecoverable because it relates to the time period between January 1, 2007 and April 1, 2007.

> There is no agreement as to whether or how the Company can recover any revenue deficiency in excess of $26.0 million.

The Board issued an interim rate order on March 26, 2007 which allowed for the recovery of $26 million in revenue deficiency by way of interim rates effective January 1, 2007 and implemented April 1, 2007, along with a rate rider to apply from April 1 to December 31, 2007. The amended rates will recover approximately $21 million in deficiency over the period April 1, 2007 to December 31, 2007, and the rate rider will recover an additional $5 million.

The Company proposes to recover any incremental revenue deficiency (that is any amount that is more than $26 million) through amended base rates and an additional rate rider to apply to the end of the test year. In the event that the Board's final decision results in a total revenue deficiency that is less than $26 million, the Company will adjust its rates accordingly.

The Company also proposes to clear all approved deferral and variance account balances on a one-time basis to rates. As set out at Issue 3.13 of the Settlement Proposal, the impact of this clearance for accounts, other than the 2006 Purchased Gas Variance Account (2006 PGVA) be a credit of approximately $23 million in favour of ratepayers, with the final amount adjusted to reflect the Board's decision in respect of the deferral and variance accounts that were reviewed and tested during the hearing. At the same time, the Company would also clear the outstanding balance in the 2006 PGVA as a one time adjustment, which will result in an offsetting debit of approximately $20 million.

As the Company's test year commenced January 1, 2007, the only implementation issue was the effective date of the new rates.

Positions of the Parties

The Company argued that circumstances outside its control prevented a timely filing of its application, including extenuating factors associated with the date of the 2006 test year Board decision and the complicated and lengthy consultative processes which were supported by all intervenors and led to positive results.

CCC stated that although there were avoidable delays caused by Enbridge, the timing of the hearing was not solely related to these delays. A number of consultatives were ongoing and there were Board scheduling issues. The Board should allow full recovery of the found revenue requirement in this case but should state as a matter of policy that may be financial consequences in the future if the delays are caused by the Company.

IGUA stated that although the Company did not initiate its application as promptly as it might have, given some extenuating circumstances in this particular case, including the consultatives, the Company should not be deprived of that portion of the agreed upon deficiency of $26 million which normally would have been recovered between January 1, 2007, and April 1, 2007. IGUA also stated that it accepts that any revenue deficiency over the agreed upon $26 million should be recovered through a rate rider to December 31, 2007, but only if in its view the impacts on large volume customers were reasonable following the Board's Decision. Otherwise, IGUA stated that it reserves the right to argue for a lower rate rider that would extend beyond December 31, 2007.

VECC supported recovery of the remaining revenue deficiency on a prospective basis but, consistent with its earlier argument, the recovery from customers should correct for the over-contribution from Rate 1 customers.

Schools referred extensively to Enbridge's testimony and argued that the Company could have filed its application earlier, therefore it should be responsible for causing the retroactivity. Schools suggested that the $5 million of the $26 million agreed upon deficiency could have been recovered from January 1, 2007 to March 31, 2007, and therefore should not now be recovered. With respect to any additional revenue deficiency to be found, the portion of such additional deficiency that would have been recovered from January 1, 2007 to the date of implementation of the new rates should not be recovered from ratepayers.

Board Findings

The prospect of retroactivity is always problematic for the Board. To be clear, having declared the Company's interim effective January 1, 2007, the effective date for the new rates in not a legal issue in this case. The Company can in this case request and the Board can grant an effective date of January 1, 2007. Rather, the issue of retroactivity is one of rate impacts and customer acceptability. The Board has stated numerous times that it does not endorse retroactivity, regardless of how the monies are recovered. The Board has attempted to work with the utilities and other parties so that retroactivity can be avoided. Some progress was made in recent years but now that progress appears to have been stalled.

The Board accepts, as many parties do, that there were extenuating circumstances in the past year which contributed to the Company's late filing. The Company had to comply with new minimum filing requirements, its evidence had to be in new formats, and the Company was engaged on a number of other important files before the Board. Also, there were a number of financially significant and complex items that were the subjects of several consultatives. However, while the use of the consultatives bore fruit on certain issues, their conclusions were not timely. Some of the consultatives did not complete their deliberations in time for the commencement of the hearing with the result that the hearing was postponed a number of times. The responsibility for that should not rest only with the Company. In the future, the Board expects parties to conclude any consultatives in adequate time for the hearing to commence when scheduled.

Recognizing these unique circumstances, the Board will not penalize the Company for the lateness of its filing, the commencement of the hearing and the resultant retroactivity. The Board expects the Company to endeavour to bring its filing cycle so that retroactivity can be avoided in the future. The Board expects all parties to act in a positive fashion to avoid retroactive ratemaking in the future.

The Board accepts the Company's proposals to implement recovery of the full revenue deficiency for the 2007 test year arising from this decision.

The Board also accepts the clearance of the balances in the deferral and variance accounts as proposed by the Company except in circumstances where the Board had made different findings in this decision.

Also, the Company in its Argument-in-Chief proposes that the Board include clearance of the 2006 PGVA balance in its decision regarding the disposition of deferral accounts tested during the hearing. The Board notes that the 2007 Settlement Proposal (p.32 of 47) indicates that parties agreed that Enbridge is not seeking to clear in the test year, certain balances, of which one was the 2006 PGVA, and these would be addressed by the Board in the future. The Board anticipates that the next QRAM application may be an opportune time for the Board to consider this matter.

The Board directs the Company to file a draft rate order reflecting the Board's findings, with an implementation date that in the Company's view would be more appropriate. Intervenors wishing to comment on the draft rate order shall file their submissions within 7 days from the Company's filing.

The Company shall include in that filing appropriate documentation in support of its draft rate order, including updates to the "N1, Tab2" series of exhibits.

COST AWARDS

On day 16 of the oral hearing the panel directed eligible parties to file their costs claims, for all costs up to and including April 13, 2007, by May 4, 2007.

Parties who intend to claim cost awards for activity subsequent to April 13, 2007, shall submit their cost claims by July 26, 2007. A copy of the cost claim must be filed with the Board and one copy is to be served on Enbridge. The cost claims must be done in accordance with section 10 of the Board's Practice Direction on Cost Awards.

Enbridge will have until August 9, 2007 to object to any aspects of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the party against whose claim the objection is being made.

The party whose cost claim was objected to will have until August 16, 2007 to make a reply submission. Again a copy of the submission must be filed with the Board and one copy is to be served on Enbridge.

DATED at Toronto, July 5, 2007.

Original signed by

Gordon Kaiser
Vice Chair and Presiding Member

Original signed by

Paul Vlahos
Member

Original signed by

Ken Quesnelle

Member

APPENDIX A

ENBRIDGE GAS DISTRIBUTION INC.

2007 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0034

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

JULY 5, 2007

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

On September 7, 2006, the Board issued a Notice of Application which was published and served in accordance with the Board's direction.

The Board issued Procedural Order No.1 on October 4, 2006, establishing the procedural schedule for all events prior to the oral hearing, as well as the Issues List for the proceedings. These scheduled events included:

- Issues conference on October 10, 2006;
- Issues Day on October 12, 2006;
- Written interrogatories to the Applicant by October 23, 2006;
- Written interrogatory responses from the Applicant by November 9, 2006;
- Intervenor evidence filed by November 14, 2006;
- Written interrogatories on Intervenor evidence by November 21, 2006;
- Responses to written interrogatories on Intervenor evidence by December 5, 2006;
- Intervenor Conference on December 7, 2006;
- Settlement Conference beginning December 11, 2006;
- Settlement Proposal by January 4, 2006;

- Board review of Settlement Proposal on January 9, 2006.
- Oral Hearing beginning on January 11, 2007

On Issues day, the Board heard submissions from Enbridge Gas Distribution Inc. ("Enbridge"), Pollution Probe Foundation ("Pollution Probe"), Industrial Gas Users Association ("IGUA"), Union Energy LP, the Consumers Council of Canada (the "Council"), Direct Energy Marketing Limited ("Direct Energy"), Superior Energy Management ("SEM"), TransAlta Energy Corp ("TransAlta"), Coral Energy, Green Energy Coalition ("GEC"), Heating, Ventilation and Air-Conditioning Coalition Inc. ("HVAC"), Energy Probe Research Foundation ("Energy Probe"), School Energy Coalition ("Schools"), the Vulnerable Energy Consumers Coalition ("VECC"), and the Low-Income Energy Network ("LIEN").

On October 20, 2006, the Board issued Decision and Procedural Order No. 2, dealing with the status of three parties as intervenors and eligibility for costs, the question of the Board's jurisdiction regarding rate affordability programs, and the approved Issues List.

Procedural Order No. 3, issued November 6, 2006, involved a Motion brought forward by LIEN for orders to:

- Extend the dates to serve and file interrogatories on the Applicant, and to file its Intervenor evidence, by 30 and 60 days respectively from the date of Board decision on their Motion;
- Confirm LIEN's eligibility for full cost awards, including newly raised issues

The Board heard LIEN's Motion on November 17, 2006.

Procedural Order No. 4, issued November 29, 2006, made the following schedule changes:

- Written interrogatories on Intervenor evidence by November 24, 2006;

- Responses to written interrogatories on Intervenor evidence by December 8, 2006;

- Oral hearing to commence January 22, 2007;

- A provision for the treatment of certain interrogatory responses as “Proposed Confidential Undertakings” with objections to such course to be filed by December 4, 2006; EGD required to file any reply submissions by December 6, 2006;

- Settlement Proposals arising from the Settlement Conference to be filed with the Board no later than January 12, 2007

On December 20, 2006, the Board issued Decision and Procedural Order No. 5, which indicated that the rate affordability issue brought forward by LIEN would not be heard in the EB-2006-0034 proceeding, and declared rates, as approved in EB-2006-0288, interim effective January 1, 2007. The Board’s decision was issued on April 26, 2007 where the majority of the panel found that the Board does not have jurisdiction to hear the rate affordability issue brought forward by LIEN.

On December 27, 2006, the Board issued Procedural Order No. 6, which set dates for a technical conference regarding Open Bill Access, involving Board Staff, Intervenors and Enbridge Gas Distribution Inc. The technical conference was held on January 10, 2007.

Decision and Procedural Order No. 7, issued January 12, 2007, provided the Board’s finding regarding confidential treatment of certain responses to interrogatories.

On April 16, 2007, the Board issued Procedural Order No. 8, regarding the status of Issue 3.6, (Corporate Cost Allocation Methodology) given the filing of new evidence on February 14, 2007. The Order set Issue 3.6 to a separate phase in this proceeding.

The following parties filed written evidence with the Board:

- Eric Hoaken on behalf of Direct Energy;
- David MacIntosh on behalf of Energy Probe;
- John DeVellis on behalf of HVAC;
- Paul Manning on behalf of LIEN;
- Michael Buonaguro on behalf of VECC, the Council, and IGUA

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board's offices.

Board Counsel and Staff	Michael Millar Richard Battista Edik Zwarenstein Colin Schuch Rudra Mukherji Khalil Viraney
Enbridge Gas Distribution Inc.	Fred Cass Patrick Hoey David Stevens Dennis O'Leary Robert Bourke
Pollution Probe	Murray Klippenstein Jack Gibbons Basil Alexander
Union Energy Limited Partnership ("Union Energy LP")	Kirsten Crain
Union Gas Limited ("Union")	Patrick McMahon Michael Penny

Industrial Gas Users Association ("IGUA")	Peter Thompson Vince DeRose
Consumers Council of Canada ("the Council")	Robert Warren Julie Girvan
Direct Energy Marketing Limited	Dave Matthews Eric Hoaken
Superior Energy Management ("SEM")	Elizabeth DeMarco
TransAlta Cogeneration LP, TransAlta Energy Corp ("TransAlta")	Elizabeth DeMarco
Ontario Energy Savings Corp	Nola Ruzycki
Green Energy Coalition	David Poch Kai Millyard
Heating, Ventilation and Air-Conditioning Coalition Inc. ("HVAC")	John De Vellis
Ontario Association of Physical Plant Administrators ("OAPPA")	Valerie Young
TransCanada Pipelines	Murray Ross Jennifer R. Scott Bernard Pelletier
Energy Probe Research Foundation ("Energy Probe")	David Macintosh Tom Adams Randy Aiken
School Energy Coalition ("Schools")	Jay Shepherd Bob Williams
Natural Gas Specialist	Jason F. Stacey
Accenture Business Services for Utilities Inc. ("ASBU")	Robert Howe
Low-Income Energy Network ("LIEN")	Paul Manning
Coral Energy Canada Inc. ("Coral")	Elisabeth DeMarco

CustomerWorks LP ("CWLP")	Margaret Sims Hilary Clark
Vulnerable Energy Consumer's Coalition ("VECC")	Michael Buonaguro Michael Janigan Roger Higgin

WITNESSES

There were 51 company employees listed as witnesses by Enbridge Gas Distribution Inc. as part of their filed application. The following is a list of these participants:

Linda Au	Capital Budget Supervisor
John W. Bayko	Director, Operations Services
Glenn W. Beaumont	Vice President, Engineering & Information Technology
Mark Bergman	Senior Analyst, Economic & Market Analysis
Robert Bourke	Manager, Regulatory Proceedings
Bradley Boyle	Treasury Project Leader
Michael Brophy	Manager, DSM & Portfolio Strategy
Irene Chan	Manager, Volumetric Analysis and Budgets
David B. Charleson	Director, Energy Policy and Analysis
Susan Clinesmith	Manager, Business Markets
Jackie Collier	Manager, Rate Design
Anne Creery	Manager, Customer Care Operations
Kevin Culbert	Manager, Regulatory Accounting
Joel Denomy	Supervisor, Economic and Market Analysis
Jackie Eliason	Manager, Finance

Robert Fox	Chief Engineer, Engineering
Tanya M. Ferguson	Manager, Customer Care Financial Administration
Malini Giridhar	Manager, Rate Research and Design
Barry Goulah	Manager, System Measurement
Paul Green	Director, Market Development
Jane Haberbusch	Director, Human Resources
Patrick J. Hoey	Director, Regulatory Affairs
John Jozsa	Manager, Tax Services
Anton Kacicnik	Manager, Cost Allocation
Sagar Kancharla	Manager, Financial and Economic Assessment
D. A. Kelly	Manager, Operational and Capital Budgets
Narin Kishinchandani	Chief Accountant
Vivian Krauchek	Manager, Gas Supply
Thomas J Ladanyi	Manager, Budgets and Planning
Kerry Lakatos-Hayward	Manager, Business Development & Strategy
Douglas Lapp	Chief Safety Officer
Lee Liauw	Manager, Scorecard & Capital Appropriation
Gerry MacDonald	Director, NGV Business Development
Andrew Mandyam	Manager, CIS Program Operations
Catherine McCowan	Manager, Operations Service
Steve McGill	Manager, Strategic Projects & market Analysis
Michael Mees	Director, Customer Care
W. Robert Milne	Manager, Distribution Planning

Stuart Murray	Manager, Financial Assessment
Byron Neiles	Vice President, Legal Regulator & Public Affairs
Barry Remington	Manager, Property Taxes
Norman Ryckman	Group Manager Business Intelligence and Support
Jody Sarnovsky	Manager, Strategic & Key Accounts
Donald Small	Manager, Gas Cost Knowledge Centre
Patricia Squires	Manager, Mass Market and New Construction Market Development
Liz Stokes-Bajcar	Manager, Human Resources Service Centre & Compensation
Michael Tremayne	Manager, Infrastructure & Marketing, NGV
Trevor Tuck	Manager, Engineering Special Projects
Annette Urquhart	Manager, Corporate Budgets & Planning
Marc Weil	Director, Information Technology
Henry Wong	Manager, Business Applications

In addition, the Company called the following witnesses:

P. Carpenter	Brattle Group

Intervenor Witnesses:

Lee Rose	Senior Vice-President, Home Services Canada, Direct Energy
Michael Shulist	The Shulist Group Inc.
Martin Luymes	Senior Director, HRAC Services and Relations, Heating, Refrigeration and Air-Conditioning Institute of Canada (HRAI)
Nancy McKeraghan	President, Canco Climate Care Inc.
Michael Latreille	Vice-President, Holmes Heating Inc.

Glen Leis	General Manager, OZZ Comfort Solutions
Roger Grochmal	President, Atlas Air ClimateCare
Paul Messenger	President, A1 Heating and Air Conditioning
Steve Kinsey	Private Investigator, Corporate Investigation Services
Laurence D. Booth	CIT Chair in Structured Finance, Rotman School of Business
David Kincaid	President and CEO, Level 5 Strategic Brand Advisors

APPENDIX B

ENBRIDGE GAS DISTRIBUTION INC.

2007 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0034

SETTLEMENT PROPOSAL

JULY 5, 2007

SETTLEMENT PROPOSAL

JANUARY 24, 2007

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1.2 Are the amounts proposed for Capital Expenditures in 2007 appropriate (B1-2-1)

1.3 Is the budget amount proposed in 2007 for Safety and Integrity projects appropriate (B1-3-1)

1.4 How should the Board deal with the Leave to Construct ("LTC") projects included in the 2007 capital budget given that there will be separate Board proceedings for the LTC projects (B1-T3-S1)

1.5 Has the Company met the requirements of the Board's directive from the 2006 rate case to file an independent cost benchmark study for the EnVision project? (B1-6-1)

1.6 What are the appropriate EnVision cost and benefits and how should they be reflected in 2007 rates?

1.7 Is the business case, including the total project amount of $133 million, proposed for the Automatic Meter Reading project ("AMR") justified? (B1-7-1)

1.8 Is the proposed recovery of AMR costs in 2007 rates appropriate?

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ISSUE	**DESCRIPTION (& EVIDENTIARY REFERENCE)**
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ISSUE	**DESCRIPTION (& EVIDENTIARY REFERENCE)**
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5	**COST ALLOCATION (Exhibit G)**
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5.2	Is the proposal to recover Demand Side Management costs in delivery charges, as opposed to load balancing charges, appropriate? (from G2-3-1 to G2-3-4)
6	**RATE DESIGN (Exhibit H)**
6.1	Is the proposal to introduce delivery demand charges for Rates 100 and 145 reasonable? (H1-1-1)
6.2	Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable? (H1-1-1)

ISSUE DESCRIPTION (& EVIDENTIARY REFERENCE)

6.3 Should the Board approve the contents of the Applicant's Rate Handbook? (H1-1-1, H2-6-1; A1-14-2)

6.4 Is the proposed treatment of bundled transportation charges and T-service credit appropriate in light of the Board's Decision in RP-2003-0203 and the settlement agreement? (H1-1-1)

7 CUSTOMER CARE SUPPORT, CUSTOMER CARE SYSTEM, AND OPEN BILL ACCESS

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision? (D1-12-3)

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account? (D1-10-1, p. 2/AppA)

7.3 Are the forecast costs of the new CIS system appropriate? (B1-5-1, p. 3)

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs? (D1-12-1, p. 2 and D3-2-1, p. 1)

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP 2005-0001? (D1-11-1 to 5)

8 OTHER ISSUES

8.1 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the NGEIR (EB-2005-0551) proceeding will be appropriately captured and reflected in this proceeding?

8.2 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the DSM

ISSUE	**DESCRIPTION (& EVIDENTIARY REFERENCE)**
	(EB-2006-0021) proceeding will be appropriately captured and reflected in this proceeding?
9	**RATE IMPLEMENTATION**
9.1	How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?
9.2	Should the Board set interim rates, effective January 1, 2007, to allow Enbridge to begin to recover its prospective revenue deficiency?

ATTACHMENTS

Appendix A- Deferral and Variance Accounts Balances

Appendix B- Approximations of rate impacts of the Settlement Proposal

PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board ("OEB" or "Board") in connection with the application of Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company"), for an order or orders approving or fixing rates for the sale, distribution, transmission, and storage of gas for its 2007 fiscal year (the "Test Year").[1] A Settlement Conference was held between December 11, 2006 and January 5, 2007 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* ("Settlement Guidelines"). Ken Rosenberg acted as facilitator for the Settlement Conference. Settlement discussions between parties continued after that time. This Settlement Proposal arises from the Settlement Conference and subsequent discussions.

Enbridge Gas Distribution and the following intervenors (collectively, the "parties"), as well as Ontario Energy Board technical staff ("Board Staff"), participated in the Settlement Conference:

CONSUMERS COUNCIL OF CANADA (CCC)
DIRECT ENERGY MARKETING LIMITED (Direct Energy)
ENERGY PROBE RESEARCH FOUNDATION (Energy Probe)
GREEN ENERGY COALITION (GEC)
HVAC COALITION INC. (HVAC)
INDUSTRIAL GAS USERS ASSOCIATION (IGUA)
ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS (OAPPA)
ONTARIO ENERGY SAVINGS L.P. (OESLP)
POLLUTION PROBE
SCHOOL ENERGY COALITION (Schools)
SUPERIOR ENERGY MANAGEMENT (a division of Superior Plus Inc.) (Superior)
TRANSALTA COGENERATION L.P. AND TRANSALTA ENERGY CORP. (TransAlta)
TRANSCANADA PIPELINES LIMITED (TransCanada)
UNION ENERGY LIMITED PARTNERSHIP (Union Energy)
UNION GAS LIMITED (Union)
VULNERABLE ENERGY CONSUMERS COALITION (VECC)

The Settlement Proposal deals with all of the issues listed at Appendix "A" to the Board's Procedural Order #2, dated October 20, 2006 (the "Issues List"). The numbers ascribed to each of the issues correlate to the section numbers in the Settlement Proposal and each issue falls within one of the following three categories:

1. ***complete settlement –*** if the Settlement Proposal is accepted by the Board, the issue will not be addressed at the hearing because Enbridge

[1] In this Settlement Proposal, the terms "2007 fiscal year", "fiscal 2007" and "Test Year" each refer to the twelve-month period commencing January 1, 2007 and ending December 31, 2007.

Gas Distribution and all other parties who take any position on the issue agree to the proposed settlement;

2. ***incomplete settlement –*** if the Settlement Proposal is accepted by the Board, portions of the issue will be addressed at the hearing because parties are only able to agree on some, but not all, aspects of the issue; and,

3. ***no settlement –*** the issue will be addressed at the hearing because the parties who participated in the negotiation of the issue are unable to reach a settlement on the issue.

More particularly, the Settlement Proposal depicts the 47 issues enumerated on the Issues List as follows:

Complete Settlement Parties will not address the issue at the hearing	**Incomplete Settlement** Parties will address one or more parts of the issue at the hearing	**No Settlement** Parties will address the issue at the hearing
25 issues completely settled Issues 1.1, 1.3 to 1.8, 2.1, 2.2, 3.1, 3.5, 3.7 to 3.9, 3.11, 3.14, 3.15, 4.1, 5.1, 5.2, 6.1, 6.4, 8.1, 8.2 and 9.2	7 issues partly settled Issues 1.2, 3.2, 3.12, 3.13, 6.2, 6.3 and 9.1	15 issues not settled Issues 2.3 to 2.6, 3.3, 3.4, 3.6, 3.10, 4.2, 4.3 and 7.1 to 7.5

Issue 3.2, which relates to the Company's O&M Budget for the Test Year is an incomplete settlement, however, it should be noted that GEC and Pollution Probe object to the settled portions of this issue. Issue 9.1, which relates to rate implementation, is an incomplete settlement, however, it should be noted that Schools objects to the settled portions of this issue.

The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise. Any parties that are identified as not having participated in the negotiations of the issue also take no position on any settlement or other wording pertaining to the issue. Board Staff participated in the Settlement Conference, and has advised the parties that it does not oppose the proposed settlement on any of the completely settled or partly settled issues. However, in accordance with the Rules and the Settlement Guidelines, Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Proposal.

The Settlement Proposal describes the agreements reached on the completely settled and partially settled issues. The Settlement Proposal identifies the parties who agree and who disagree with each settlement, or alternatively who take no position on the issue. Finally, the Settlement Proposal provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties who agree with the individual settlements are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the settled issues. In the event that the Board does not accept the proposed settlement of any issue, further evidence may be required on the issue for the Board to consider it fully.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit A1, Tab 8, Schedule 1 is referred to as A1-8-1. A concise description of the content of each exhibit is also provided. In this regard, Enbridge Gas Distribution's response to an interrogatory is described by citing the name of the party and the number of the interrogatory (e.g., Board Staff Interrogatory #1). The identification and listing of the evidence that relates to each settled issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

The parties agree that all positions, information, documents, negotiations and discussion of any kind whatsoever which took place or were exchanged during the Settlement Conference are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Proposal.

According to the Settlement Guidelines (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge Gas Distribution and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

Issues 1.1 to 1.8, 2.1, 2.2, 3.2, 3.5, 3.7 to 3.9, 3.11 to 3.15 and 9.1 have been settled by parties as a package (the “package”), subject to the objections of GEC, Pollution Probe and Schools, as noted earlier, and none of the parts of this package are severable. All parties agree that, for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company’s April 1, 2007 QRAM is implemented. GEC’s and Pollution Probe’s agreement in this regard is subject to any later adjustments to the Company’s recovery of revenue deficiency that might be required as a result of

Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1. Subject to considering the objections of GEC, Pollution Probe and Schools during the hearing, if the Board does not, prior to the commencement of the hearing of the evidence in EB-2006-0034, accept the package in its entirety, then there is no Settlement Proposal (unless the parties agree that any portion of the package that the Board does accept may continue as part of a valid Settlement Proposal). None of the parties can withdraw from the Settlement Proposal except in accordance with Rule 32 of the Rules. Finally, unless stated otherwise, the settlement of any particular issue in this proceeding is without prejudice to the rights of parties to raise the same issue in any future proceeding.

OVERVIEW

In order to address certain issues that have continued to be the subject of debate and discussion over a number of years, and in order to satisfy Board directions from the Decision with Reasons in the EB-2005-0001 case (the 2006 rate case), during the past year the Company has entered into a number of consultative processes with stakeholders. These consultatives were convened in respect of EnVision (issues 1.5 and 1.6), Corporate Cost Allocation (issues 3.6 and 3.7), customer care and CIS (issues 3.2 and 7.1 to 7.4) and open bill access (issue 7.5). These consultative processes have contributed greatly to the ability of all parties to come to settlements on many of these issues, as set out below. Several of the consultative processes are ongoing and may lead to settlement of additional issues. If additional issues are partly or completely settled, parties propose to file a supplementary settlement agreement that would explain the settlements, and the incremental financial impacts of such settlements.

Parties have been able to agree upon the package, which includes settlement of many of the issues raised in this proceeding. While some issues remain outstanding and unresolved, the impact of this Settlement Proposal, if accepted, is that the scope and length of the proceeding will be substantially reduced.

The Company's Application sought recovery of a revenue deficiency of $167.8 million. This figure was updated to $158.7 million in Impact Statement No. 1, to account for, among other things, the ROE for the Test Year of 8.39%.

Parties have agreed upon the settlement package of issues that, if accepted, would reduce the revenue deficiency by $76.7 million. This would result in a remaining revenue /c
deficiency of $82.0 million. /c

The implementation of the settlement package of issues will result in a revenue deficiency of $29.9 million, based on the Company's filing which expresses the revenue deficiency /c
as being relative to the Board-approved rates for F2006, and all of the items that make up

and contribute to those rates including, for example, the agreed-upon level of degree days for F2006.

The issues that are not settled by the Settlement Proposal represent an additional revenue deficiency amount of $52.1 million, based on the Company's filing, which will /c require determination by the Board in the hearing. Based on positions that may be taken by parties in the hearing, the potential outcomes arising from the determination of these unsettled issues by the Board range from an incremental revenue sufficiency of approximately $5 million to an incremental revenue deficiency of $52.1 million. /c

Some intervenors assert that, if they are successful on outstanding issues (in particular issues related to Issue 2.2 regarding degree days), then there could be a revenue sufficiency in respect of those issues. Parties are able to agree, however, that for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. This amount of $26.0 million will be subtracted from the total revenue deficiency resulting from the Board's final decision in this proceeding (which will include all impacts of this Settlement Proposal). The resulting revenue deficiency (or sufficiency) will be reflected and recovered in rates by the Company, subject to the outcome of Issue 9.1.

When implemented, the recovery of an additional $26.0 million will result in average increases, on an annual basis, of approximately 2% for Rate 1 customers, 1% for Rate 6 customers and between 0% and 2% increases for other rate classes. These average rate increases are relative to the July 1, 2006 QRAM rate and are calculated for a T-service customer, excluding commodity costs, and do not include impacts from the phase-in of cost allocation changes on October 1, 2006 and October 1, 2007. When these rate impacts are compared to the January 1, 2007 QRAM rate, the results are virtually identical as shown in Appendix B. The phase-in of cost allocation changes on October 1, 2007 will reduce the amounts recovered from Rate 1 and Rate 6 by approximately $5.01 million and $4.8 million respectively, and increase the amounts recovered from Rate 115, Rate 135 and Rate 170 by about $5.97 million, $0.6 million and $3.2 million respectively, as shown in Appendix B. The determination by the Board of the issues that are not settled will have additional rate impacts.

Attached as Appendix B is an approximation of the annual T-service rate increases that would result from the recovery of additional amounts of $26.0 million (the immediate additional amount to be recovered if the Settlement Proposal is accepted) and $82.0 /c million (the maximum recoverable revenue deficiency if the Settlement Proposal is accepted and the Board decides the unsettled issues by adopting the Company's position on these issues). These approximations do not take account of the clearance of deferral and variance accounts, the phase-in of cost allocation changes or any allocation changes that might result from the resolution of Issue 6.2. These average annual T-service rate impact estimates are not indicative of the percentage T-service rate increase that will occur on April 1, 2007, compared to T-service rates in force on March 31, 2007. T-service rate increases effective April 1, 2007 will include the rate increase associated with the nine month Rate Rider described in Issue 9.1. The Company believes, based on the analysis that it has undertaken, that these approximations of average annual T-service rate impacts, which are expressed relative to the July 1, 2006 QRAM rates and the January 1, 2007 QRAM rates, and are calculated for a T-service customer excluding commodity costs, are correct within +/- 0.5%.

1 RATE BASE (Exhibit B)

1.1 Are the amounts proposed for the 2007 Rate Base appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties have reached a global settlement of all 2007 Rate Base issues, except for issues related to the capital budget for the new CIS system. Issues related to the new CIS system are discussed below at Issues 7.2 to 7.4. The capital spending for the new CIS system will have no rate base impact in 2007. Parties agree that the Company will reduce the revenue deficiency associated with 2007 Rate Base issues by a total of $8 million, as compared to the Company's filed evidence. This will result in a 2007 capital budget of approximately $300 million, plus the cost of the Portlands Energy Centre Leave to Construct project, which is estimated at $18 million during the Test Year. The Portlands Energy Centre project, if approved in the leave to construct application, will not affect rates for the Test Year. Parties believe that the Board's consideration of the Portlands Energy Centre in the leave to construct application should be consistent with the principles set out under Issue 1.4 below.

Parties agree that the 2007 capital budget is an envelope amount, and the Company will have discretion to determine which items will be removed or changed from the Company's filed capital budget in order to reduce the overall level of that budget. Notwithstanding this discretion, the Company agrees that it will not proceed with the Automatic Meter Reading (AMR) project. Intervenors do not necessarily accept, and presently take no position on, the Company's decisions as to how it will allocate and spend the 2007 capital budget. Parties agree that, assuming the incentive regulation rate setting process allows for it, a normal review of the Company's capital spending in the Test Year may be undertaken as part of the rate setting process for 2008. The issue of capital spending on the EnergyLink program, included in Issue 3.4, is not settled, but the Board's decision on that issue will not affect the overall capital budget for the Test Year, only the Company's ability to allocate funds to EnergyLink within that budget. Parties accept the Company's opening rate base for 2007.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Utility Rate Base
B1-1-2	Utility Rate Base Year to Year Summary
B1-2-1	Rate Base Capital Budget
B3-1-1	Ontario Utility Rate Base – Comparison of 2007 Test Year to 2006 Bridge Year
B3-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2007 Test Year
B3-1-3	Working Capital Summary of Average of Monthly Averages 2007 Test Year
B3-2-1	Utility Capital Expenditures Comparison Budget 2007 and Estimated 2006
B3-2-2	2007 Capital Expenditures by Project (Projects Exceeding $500,000)
B3-2-3	Gross Customer Additions and Average Cost per Customer Addition Budget 2007 and Estimated 2006
B3-2-4	System Expansion Portfolio – 2007
F3-1-3	Utility Rate Base 2007 Test Year
I-1-1 to 3	Board Staff Interrogatories 1 to 3
I-9-4 and 7	IGUA Interrogatories 4 and 7
I-16-1 to 3	SEC Interrogatories 1 to 3
I-24-5 to 7	VECC Interrogatories 5 to 7
L-9-1	Evidence of IGUA
M1-1-1	Impact Statement #1

1.2 Are the amounts proposed for Capital Expenditures in 2007 appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

See Issue 1.1.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-2-1	Rate Base Capital Budget
B1-2-2	Details of Capital Expenditure and Justification for Major Capital Projects over $500,000
B1-3-1	Safety & Integrity Initiatives
B1-3-2	Leave to Construct Projects
B1-4-1	Information Technology Capital Budget
B1-5-1	CIS Project
B1-6-1	EnVision Project
B1-7-1	Automated Meter Reading (AMR)
I-1-4 to 6	Board Staff Interrogatories 4 to 6
I-2-1 to 4	CCC Interrogatories 1 to 4
I-9-2 and 5 to 6	IGUA Interrogatories 2 and 5 to 6

I-16-4 to 10	SEC Interrogatories 4 to 10
I-24-8 to 12	VECC Interrogatories 8 to 12

1.3 Is the budget amount proposed in 2007 for Safety & Integrity projects appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

See Issue 1.1. The Company will determine the 2007 capital expenditures budget for Safety and Integrity projects within the envelope set out under Issue 1.1.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-3-1	Safety & Integrity Initiatives
I-1-7	Board Staff Interrogatory 7
I-2-5 to 7	CCC Interrogatories 5 to 7
I-9-8	IGUA Interrogatory 8
I-16-11 to 12	SEC Interrogatories 11 to 12
I-24-13	VEC Interrogatory 13

1.4 How should the Board deal with the Leave to Construct (“LTC”) projects included in the 2007 capital budget given that there will be separate Board Proceedings for the LTC projects?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties are of the view that the Board’s decisions determining the appropriate total amount of capital spending by the Company in any test period are most suitably made in a rate application. In general, parties agree that the Board’s decision with respect to overall capital spending does not imply specific approval of any individual leave to construct projects (“LTC Projects”), nor a decision as to the economic feasibility of any individual LTC Project. Similarly, parties agree that, generally, a decision with respect to the economic feasibility of an individual LTC

Project does not, in and of itself, imply that it is appropriate to include capital spending pertaining to that LTC Project in the capital budget for a test year used by the Board to establish rates.

In the context of the foregoing, the parties agree that the Board should deal with LTC Projects included in any test year capital budget as follows:

1. The total capital expenditures budget for a particular test year, to be considered and approved in a rate application, should include some evidence on individual LTC Projects planned for that year. However, the Board should not be asked to approve individual LTC Projects in a rate case. In a rate case, evidence with respect to individual LTC Projects need not be as extensive as the evidence required to support a LTC Application.

2. The economic feasibility of an individual project is considered in a leave to construct application. A LTC Application should not result in any adjustment to the Company's capital expenditures budget aside from exceptional circumstances, and in those cases the Board should consider and make the adjustment expressly.

3. A LTC Application can be heard by the Board prior to its consideration of the capital budget consequences of the LTC Project in a rates proceeding. In the event the Board approves a LTC Application, it will not be necessary to examine the justification for the LTC Project in a subsequent rate proceeding although the issue of the appropriate size of the overall capital budget would remain in issue in that hearing, and the leave to construct approval could inform that decision.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-3-2	Leave to Construct Projects
I-1-8 to 9	Board Staff Interrogatories 8 to 9
I-2-8	CCC Interrogatory 8
I-9-9	IGUA Interrogatory 9
I-16-13 to 14	SEC Interrogatories 13 to 14
I-19-4	TransAlta Interrogatory 4

1.5 Has the Company met the requirements of the Board's directive from the 2006 rate case to file an independent cost benchmark study for the EnVision project?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that the Company has met the requirements of the Board's directive from the EB-2005-0001 Decision with Reasons by filing an independent cost benchmark study for the EnVision project.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B2-2-1	Compass Report – Envision Cost Benchmark Analysis
B1-6-1	EnVision Project

1.6 What are the appropriate EnVision cost and benefits and how should they be reflected in 2007 rates?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that Compass carried out an appropriate cost benchmark study of the EnVision Project. Parties differ on how that benchmark should be applied in determining the costs and benefits associated with EnVision that should be reflected in rates. In order to resolve the EnVision issues in this proceeding, the Company has agreed to reduce the revenue requirement by $500,000 through a reduction in the 2007 Other O&M budget. This reduction is reflected and included in the $181.5 million total Other O&M budget agreed to below at Issue 3.2. The Company will continue to report annually to stakeholders on the achievement of EnVision benefits in the form and the manner set out in Tables 1 and 2 in Exhibit B1/T6/S1/pp 8-9. Parties agree that unless there is a change in the overall NPV of the EnVision project, there will be no need to revisit the EnVision project in future regulatory proceedings.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B2-2-1	Compass Report – Envision Cost Benchmark Analysis
B1-6-1	EnVision Project
1-2-9 to 17	CCC Interrogatories 9 to 17
1-16-15	SEC Interrogatory 15

1.7 Is the business case, including the total project amount of $133 million, proposed for the Automatic Meter Reading project ("AMR") justified?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

As part of the global settlement of 2007 rate base issues, the Company agrees not to proceed with the AMR project.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-7-1	Automated Meter Reading (AMR)
I-1-10 to 13	Board Staff Interrogatories 10 to 13
I-2-18 to 22	CCC Interrogatories 18 to 22
I-9-11	IGUA Interrogatory 11
I-16-16	SEC Interrogatory 16
I-24-14	VECC Interrogatory 14

1.8 Is the proposed recovery of AMR costs in 2007 rates appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> As part of the global settlement of 2007 rate base issues, the Company agrees not to proceed with the AMR project. As a result, this issue is no longer relevant.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-7-1	Automated Meter Reading (AMR)
1-24-15 to 16	VECC Interrogatories 15 to 16

2 OPERATING REVENUE (Exhibit C)

2.1 Is the proposed amount for 2007 Transactional Services revenue appropriate, and is the associated sharing mechanism in accordance with the 2006 decision?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that the Company will share net transactional services revenues with ratepayers on a 75:25 basis in favour of ratepayers for transportation-related transactional services and on a 90:10 basis in favour of ratepayers for storage-related transactional services. The Company agrees to credit $8 million in transactional services revenue to ratepayers, to be credited to the revenue requirement for the purpose of setting rates for the Test Year. This credit will not be allocated as between transportation and storage transactional services. The 2007 Transactional Services Deferral Account will include the total of the ratepayers' shares of the net transactional services revenue for transportation-related and for storage-related transactional services, less the $8 million credit and the O&M costs associated with storage-related transactional services (estimated at $.1 million in the Company's updated evidence at Ex. C1-4-2). For greater certainty, if the result of these calculations is that the year-end balance in the 2007

Transactional Services Deferral Account would be less than zero, the balance shall be deemed to be zero.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-4-1	Transactional Services Revenue
C1-4-2	Transactional Services – Supplementary Evidence
I-1-14 to 15	Board Staff Interrogatories 14 to 15
I-2-23	CCC Interrogatory 23
I-9-13	IGUA Interrogatory 13
1-16-17	SEC Interrogatory 17
I-24-17 to 18	VECC Interrogatory 17 to 18
M1-1-1	Impact Statement #1

2.2 Is the proposed total 2007 Other Revenue Forecast appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree to increase the forecast for Other Operating Revenue for the Test Year from $23.7 million to $28.9 million, inclusive of the $3.5 million incremental impact of the resolution of the Transactional Services issue (described above at Issue 2.1), an increase of $1.0 million from the forecast of Other Service Revenues in the Company's evidence and the imputation of revenue of $700,000 for the Natural Gas Vehicles (NGV) program for the Test Year (in order to reflect the revenue deficiency of the NGV program).

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-5-1	Other Service and Late Payment Penalty Revenues
C3-5-1	Rate of Return on Capital Employed in the Natural Gas Vehicles Program

I-1-16	Board Staff Interrogatory 16
I-2-24 to 25	CCC Interrogatories 24 and 25
I-16-18	SEC Interrogatory 18
I-24-19 to 22	VECC Interrogatories 19 to 22
M1-1-1	Impact Statement No. 1
M1-2-5	Change in Revenue Requirement

2.3 Is the forecast of degree days appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C2-4-1	Budget Degree Days
I-1-17	Board Staff Interrogatory 17
I-9-3 and 14	IGUA Interrogatories 3 and 14
1-5-1 to 12	Energy Probe Interrogatories 1 to 12
1-16-19 to 20	SEC Interrogatories 19 to 20
L-9-1	Evidence of IGUA

2.4 Are the average use-per-customer forecasts for rate class 1 and rate class 6 appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
C2-3-1	Average Rate Use 1
C2-3-2	Average Use Rate 6
I-1-18	Board Staff Interrogatory 18
I-2-26 to 28	CCC Interrogatories 26 to 28
I-16-21 to 23	SEC Interrogatories 21 to 23
I-24-22 to 25	VECC Interrogatories 22 to 25

2.5 Is the proposed 2007 contract gas volume and revenue forecast appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
I-1-19	Board Staff Interrogatory 19
I-1-12	IGUA Interrogatory 12

2.6 Is the proposed 2007 General Service gas volume and revenue forecast appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
C1-1-1	Operating Revenue Summary
C1-2-1	Revenue Forecast
C3-1-1	Utility Operating Revenue 2007 Test Year
C3-1-2	Comparison of Utility Operating Revenue Budget 2007 and Estimate 2006
I-1-20	Board Staff Interrogatory 20
1-24-23 to 25	VECC Interrogatories 23 to 25

3 OPERATING COST (Exhibit D)

3.1 Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's forecast of the cost consequences of the gas supply portfolio for the Test Year.

The Company agrees with certain parties that, when the issues list for the Natural Gas Forum proceeding about QRAM methodology is discussed, the Company will support the inclusion of an issue regarding the detailed calculation of the PGVA Reference Price.

Participating Parties: All parties participated in the negotiation and settlement of this issue except GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Cost of Gas, Transportation and Storage
D1-4-2	Status of Contracts
D3-3-1	Summary of Gas Cost to Operations
D3-3-2	Summary of Gas Storage and Transportation Costs Fiscal 2007
D3-3-3	Canadian Peak Day Supply Mix
D3-3-4	Monthly Pricing Information
D3-3-5	Gas Supply/Demand
I-1-21	Board Staff Interrogatory 21
I-2-29	CCC Interrogatory 29
I-5-16 to 17	Energy Probe Interrogatory 16 to 17
I-9-16	IGUA Interrogatory 16
I-18-6	Superior Interrogatory 6
I-21-1 to 9	TransCanada Interrogatories 1 to 9
I-24-26	VECC Interrogatory 26

3.2 Is the overall level of the 2007 Operation and Maintenance Budget appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

> The Company's overall Operations and Maintenance (O&M) budget, as filed in Impact Statement No. 1, for the Test Year totalled $365.8 million and can be divided into a number of categories: (i) customer care expenses (including CIS, internal costs and provision for uncollectibles) – filed as $120.1 million; (ii) corporate cost allocations – filed as $22.9 million; (iii) demand side management (DSM) programs – filed as $22.0 million; and (iv) Other O&M – filed as $200.8 million. The Company has also included transition costs of $10 million related to customer care as a separate line item in its filing.
>
> Issues related the Company's customer care O&M budget (including the transition costs) are discussed below at Issues 7.1 to 7.4. Parties, except for GEC and Pollution Probe, agree on the balance of the Company's O&M budget for the Test Year.
>
> Parties acknowledge that the Company's O&M DSM budget for the Test Year shall be $22.0 million, as set out in the Board's Decision with Reasons in EB-2006-0021 (the DSM generic hearing).
>
> Parties agree that the Company's O&M budget for corporate cost allocations for the Test Year shall be $18.1 million. Parties agree to the overall level of this budget, but there is no specific agreement as to the amounts of each of the

individual allocations. The issues about the corporate cost allocation methodology set out in Issue 3.6 remain unsettled.

Parties, except for GEC and Pollution Probe, agree that the Company's Other O&M budget for the Test Year, filed as $200.8 million, shall be reduced by $19.3 million to $181.5 million. Subject to the comments below, parties agree that the amount of the Other O&M budget is an envelope amount and the Company will have discretion to determine which items will be removed or changed from the Company's Other O&M budget as filed in order to reduce the overall level of that budget. Intervenors do not necessarily accept, and presently take no position on, the Company's decisions as to how it will allocate and spend the 2007 Other O&M budget.

Notwithstanding the agreement on the overall level of the Company's Other O&M budget for the Test Year, parties agree that certain components of the Company's Opportunity Development planned activities for the Test Year, specifically marketing activities, fuel switching and EnergyLink, will be examined before the Board. Parties, except for GEC and Pollution Probe, agree that the examination of those sub-issues before the Board will not impact on the $181.5 million agreed-upon level of the Other O&M budget for the Test Year. Subject to the exception set out below, parties other than GEC and Pollution Probe agree that they will not take any position in this proceeding on how the Company ought to allocate the agreed-upon $181.5 million Other O&M budget. Notwithstanding the foregoing, in the event that the Board determines that the Company may not proceed with EnergyLink, it is understood that Schools and/or HVAC may advance arguments about how the Company ought to spend the O&M amounts totaling $1.3 million (Ex. I-26-4) that were otherwise budgeted for EnergyLink. Notwithstanding the foregoing, it is also understood that VECC may advance arguments that the Company ought to allocate funds as budgeted of $925,000 to low income fuel switching (Ex. 1-24-29). Additionally, the Company agrees that from and after the date of the Board's decision in this proceeding, it will not allocate any portion of the agreed-upon $181.5 million Other O&M budget to any specific marketing, fuel switching or EnergyLink activities that the Board specifically states the Company should not be undertaking.

GEC and Pollution Probe do not agree to the $181.5 million Other O&M budget. GEC and Pollution Probe wish to examine the Company's Opportunity Development (OD) O&M budget separately and do not agree to the overall level of $181.5 million for the Other O&M budget. No other parties, including the Company, will support or argue for any change (increase or decrease) to the agreed-upon Other O&M budget of $181.5 million.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, OAPPA, OESLP, Superior, TransCanada, TransAlta, Union Gas.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue except Pollution Probe and GEC.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D1-2-1	Operating, Maintenance and Other Costs
D2-1-1	Corporate Cost Allocation
D3-1-1	Operating Cost 2007 Test Year
D3-2-1	Operating Cost Comparison of Utility Cost and Expenses Budget 2007 and Estimate 2006
D3-2-2	Operating and Maintenance Expense by Department
D3-2-3	Operating and Maintenance Expense by Cost Type
I-1-22 to 24	Board Staff Interrogatories 22 to 24
I-2-30 to 35	CCC Interrogatories 30 to 35
I-9-2, 4 and 15	IGUA Interrogatories 2, 4 and 15
I-15-1 to 4	Pollution Probe Interrogatories 1 to 4
I-16-24 to 29	SEC Interrogatories 24 to 29
I-24-27 to 28	VECC Interrogatories 27 to 28
L-9-1	Evidence of IGUA
M1-1-1	Impact Statement #1

3.3 Is the Company's proposed fuel switching program appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-8-1	Opportunity Development – Market Development
I-1-25	Board Staff Interrogatory 25
I-2-36 to 39	CCC Interrogatories 36 to 39
I-7-1	GEC Interrogatory 1
I-22-6	Union Energy Interrogatory 6
I-24-29	VECC Interrogatory 29
I-26-1 to 3	HVAC Interrogatory 1 to 3

3.4 Is the Company's proposed Energy Link program appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
I-22-6	Union Energy Interrogatory 6
I-24-30	VECC Interrogatory 30
I-26-4 to 10	HVAC Interrogatories 4 to 10
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-36 to 46	Enbridge Gas Distribution Interrogatories of Union Energy 36 to 46
I-30-1 to 21	Enbridge Gas Distribution Interrogatories of HVAC 1 to 21

3.5 Is the budget for Human Resources related costs appropriate?

(Complete Settlement)

There is an agreement to settle this issue as part of the package, as follows:

> Parties agree that any Human Resources related costs determined by the Company to be appropriate in the Test Year will be included as part of the agreed-upon $181.5 million Other O&M budget.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Costs and Maintenance and Other Costs
D1-2-2	Employee Expenses and Workforce Demographics
D3-2-4	Salaries and Wages and FTE Forecast 2007 Test Year
I-1-26	Board Staff Interrogatory 26
I-2-40 to 43	CCC Interrogatories 40 to 43
I-16-30 to 37	SEC Interrogatories 30 to 37
I-24-31 to 33	VECC Interrogatories 31 to 33

3.6 Do the revisions to the Regulatory Cost Allocation Methodology (RCAM) meet the Board's directives in the 2006 decision?

(No Settlement)

There is no agreement to settle this issue.

The issue of whether the revisions to RCAM meet the Board's directives from the 2006 decision has been a subject of the corporate cost allocation consultative. At this time, the final report from the consultant retained on behalf of the consultative has not been filed. As a result, no settlement can be reached on this issue at this time.

Evidence: The evidence in relation to this issue includes the following:

D2-1-1	Corporate Cost Allocation
G1-1-1	Corporate Cost Allocation Methodology
I-16-38 to 39	SEC Interrogatories 38 to 39

3.7 Is the proposed level of corporate cost allocation for 2007 appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that the Company's O&M budget for corporate cost allocations for the Test Year shall be $18.1 million. Parties agree to the overall level of this budget, but there is no specific agreement as to the amounts of each of the individual allocations.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Maintenance and Other Costs
D2-1-1	Corporate Cost Allocation
I-1-27 to 28	Board Staff Interrogatories 27 to 28
I-9-1	IGUA Interrogatory 1
I-24-34 to 37	VECC Interrogatories 34 to 37

3.8 Is Company's forecast level of Regulatory and OEB related costs for 2007 appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that the Company's Regulatory and OEB related costs will be included as part of the agreed-upon Other O&M budget and that variances from the budget for 2007 rate proceeding related expenses will be recorded in the 2007 Ontario Hearings Costs Variance Account for consideration and disposition in a future proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Maintenance and Other Costs
D1-9-1	Regulatory Costs
I-1-29 to 30	Board Staff Interrogatories 29 to 30
I-2-44	CCC Interrogatory 44
I-16-40	SEC Interrogatory 40

3.9 Is Enbridge's decision to change to a December 31 taxation year-end , in 2007, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Intervenors have relied on the Company's evidence that the change of taxation year-end for the Enbridge Gas Distribution Inc. corporate entity has no impact on the Company's 2007 cost of service. In conjunction with the agreement with respect to Issue 3.15, intervenors accept the Company's evidence in this regard.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-5-1	Taxation Year-End Change

I-1-31 to 34	Board Staff Interrogatories 31 to 34
I-16-41	SEC Interrogatory 41

3.10 Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-4-3	Gas Supply Risk Management
I-1-35 to 36	Board Staff Interrogatories 35 to 36
I-2-45	CCC Interrogatory 45
I-5-18 to 27	Energy Probe Interrogatories 18 to 27
I-18-7	Superior Interrogatory 7
I-24-38 to 39	VECC Interrogatories 38 to 39
L-5-1	Evidence of Energy Probe
I-36-1 to 6	Enbridge Gas Distribution Interrogatories of Energy Probe 1 to 6

3.11 Is the proposal to change depreciation rates for 2007, as proposed in the depreciation study, and the impact on 2007 customer rates, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> The Company agrees not to proceed with its request to change depreciation rates for 2007. Intervenors agree not to challenge the Company's existing depreciation rates for 2007. Notwithstanding this agreement, parties may examine the existing level of the Company's depreciation rates in the context of discussing and examining other outstanding issues in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-13-1	Depreciation Rate Change
D2-2-1	Depreciation Study

I-1-37 to 46	Board Staff Interrogatories 37 to 46
I-5-13 to 14	Energy Probe Interrogatories 13 to 14
I-9-18	IGUA Interrogatory 18
I-16-42 to 41	SEC Interrogatories 42 to 43
I-24-39.1 to 39.3	VECC Interrogatories 39.1 to 39.3
L-9-1	Evidence of IGUA

3.12 Is the proposal for the establishment of 2007 Deferral and Variance Accounts appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

The Company's proposal to establish the following deferral and variance accounts for the Test Year is accepted by the parties for the reasons set out in the Company's evidence:

2007 Purchased Gas Variance Account ("2007 PGVA")
2007 Transactional Services Deferral Account ("2007 TSDA")
2007 Unaccounted for Gas Variance Account ("2007 UAFVA")
2007 Union Gas Deferral Account ("2007 UGDA")
2007 Class Action Suit Deferral Account ("2007 CASDA")
2007 Debt Redemption Deferral Account ("2007 DRDA")
2007 Deferred Rebate Account ("2007 DRA")
2007 Gas Distribution Access Rule Costs Deferral Account ("2007 GDACRDA")
2007 Manufactured Gas Plant Deferral Account ("2007 MGPDA")
2007 Ontario Hearing Costs Variance Account ("2007 OHCVA")
2007 Electric Program Earnings Sharing Deferral Account ("2007 EPESDA")
2007 Unbundled Rate Implementation Cost Deferral Account ("2007 URICDA")
2007 Unbundled Rates Customer Migration Deferral Account ("2007 URCMDA")
2007 Demand-Side Management Variance Account ("2007 DSMVA")
2007 Lost Revenue Adjustment Mechanism ("2007 LRAM")
2007 Shared Savings Mechanism Variance Account ("2007 SSMVA")
2007 Income Tax Rate Change Variance Account ("2007 ITRCVA")

There is no agreement to the establishment of the following deferral and variance accounts, as those accounts are being dealt with as part of the customer care/CIS consultative process and through Issues 7.2 to 7.4:

2007 Customer Information System Procurement Deferral Account ("2007 CISPDA")
2007 Customer Care Procurement Deferral Account ("2007 CCPDA")
2007 Customer Care Supplier Transition Variance Account ("2007 CCSTVA")

There is no agreement to the establishment of the following deferral account, as it is being dealt with as part of the open bill consultative process and through Issue 7.5:

2007 Open Bill Access Sharing Deferral Account ("2007 OBASDA")

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Deferral and Variance Accounts
D1-7-3	Deferral and Variance Account Balances
I-1-47	Board Staff Interrogatory 47
I-2-46 to 48	CCC Interrogatories 46 to 48
I-7-2	GEC Interrogatory 2

3.13 Is the proposal for the disposition of existing Deferral and Variance Accounts appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

Enbridge Gas Distribution filed a summary of the actual deferral account and variance account balances for F2006 (D1-7-3); the summary is reproduced in Appendix A. The result of clearing certain of these accounts is that Enbridge Gas Distribution will credit customers $23.258.7 million in principal plus interest, based upon the December 31, 2006 balances, for F2006.

The balances recorded in the following deferral and variance accounts established for F2006, and the proposed clearance of such balances at the same time as the final rate order in this proceeding is implemented, are accepted by the other parties for the reasons given in the supporting evidence:

<u>Non Commodity Related Accounts</u>

2004 Demand-Side Management Variance Account ("2004 DSMVA")
2004 Lost Revenue Adjustment Mechanism ("2004 LRAM")
2004 Shared Savings Mechanism Variance Account ("2004 SSMVA")
2006 Deferred Rebate Account (“2006 DRA”)
2006 Debt Redemption Deferral Account (“2006 DRDA”)
2006 Ontario Hearing Costs Variance Account (“2006 OHCVA”)

<u>Commodity Related Accounts</u>

2006 Unaccounted for Gas Variance Account (“2006 UAFVA”)
2006 Transactional Services Deferral Account (“2006 TSDA”)

2006 Union Gas Deferral Account ("2006 UGDA")

Enbridge Gas Distribution does not seek to clear, in the Test Year, the balances recorded in the following deferral and variance accounts. Parties agree that the following previously-approved deferral and variance accounts are continued and the clearance of these accounts will be addressed by the Board in the future.

<u>Non Commodity Related Accounts</u>

2006 Demand-Side Management Variance Account ("2006 DSMVA")
2005 Demand-Side Management Variance Account ("2005 DSMVA")
2006 Lost Revenue Adjustment Mechanism ("2006 LRAM")
2005 Lost Revenue Adjustment Mechanism ("2005 LRAM")
2006 Shared Savings Mechanism Variance Account ("2006 SSMVA")
2005 Shared Savings Mechanism Variance Account ("2005 SSMVA")
2006 Manufactured Gas Plant Deferral Account (“2006 MGPDA”)
2006 Corporate Cost Allocation Deferral Account (“2006 CCAMDA”)
2006 Class Action Suit Deferral Account (“2006 CASDA”)

<u>Commodity Related Account</u>

2006 Purchased Gas Variance Account ("2006 PGVA")

While Enbridge Gas Distribution seeks to clear the balances recorded in the following deferral and variance accounts in the Test Year, there is no agreement as to whether this is appropriate and these accounts will be addressed at the hearing:

2006 Gas Distribution Access Rule Costs Deferral Account (“2006 GDARCDA”)
2005 Gas Distribution Access Rule Costs Deferral Account (“2005 GDARCDA”)
2006 Alliance Vector Appeal Costs Deferral Account (“2006 AVACDA”)
2006 Gas Supply Risk Management Program Deferral Account (“2006 GSRMPDA”)
2006 Electric Program Earnings Sharing Deferral Account (“2006 EPESDA”)
2006 Unbundled Rate Implementation Cost Deferral Account (“2006 URICDA”)

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Deferral and Variance Accounts
D1-7-2	Proposed Clearing of the 2006 Deferral Accounts
D1-7-3	Deferral and Variance Account Balances
A1-13-1	Status of Board Directives from Previous Board Decisions and/or Orders
A3-3-1	Financial Statements – Enbridge Gas Distribution Historical 2005 Year

A3-4-1	Annual Report (Actual) and Management Discussion and Analysis (MD&A)
I-2-49	CCC Interrogatory 49
I-16-44 to 45	SEC Interrogatories 44 to 45
I-24-40	VECC Interrogatory 40

3.14 Are the amounts proposed to be included in rates for capital and property taxes appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

The Company agrees to a $1.3 million reduction in its forecast of municipal property and other taxes for the Test Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D3-1-1	Operating Cost 2007 Test Year
I-9-3	IGUA Interrogatory 3
I-2-50	CCC Interrogatory 50

3.15 Is the amount proposed to be included in rates for income taxes, including the methodology, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties accept the Company's methodology for income taxes, and the amount to be included in rates for income taxes, for the purpose of setting rates for the Test Year, without prejudice to the ability of any party to raise issues with respect to the methodology and its resulting calculations, including but not limited to which inclusions and deductions are appropriate, in future rate proceedings. The Company agrees to create a 2007 Income Tax Rate Change Variance Account to capture the impact of any corporate income tax rate changes against Fiscal 2007 Board Approved taxable income (versus the Company's forecast of corporate income tax rates) that occur in 2007 as a result of Provincial and Federal government budgets that are passed in the Test Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

A3-2-1	Financial Statements – Utility Proforma Statements for Bridge and Test Year
A3-3-1	Financial Statements – Enbridge Gas Distribution Historical 2005 Year
A3-4-1	Annual Report (Actual) and Management Discussion and Analysis (MD&A)
A3-5-3	Annual/Audited Financial Reports (Historical) Enbridge Inc. – 2005 Year
D3-1-1	Operating Cost 2007 Test Year
I-16-46 to 47	SEC Interrogatories 46 to 47

4 COST OF CAPITAL (Exhibit E)

4.1 What is the Return on Equity (ROE) for EGDI for the 2007 test year as calculated pursuant to the ROE Guidelines?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties agree that the ROE for the Company for the 2007 test year is 8.39%, as calculated pursuant to the ROE guidelines.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E2-1-1	Utility Business and Financial Risks
E2-1-2	Enbridge Gas Distribution Utility Business Risks – Environment
E2-1-3	Utility Equity Thickness Financial Risk Update
E2-2-1	Calculation of ROE

E3-1-1	Cost of Capital 2007 Test Year
E3-1-2	Summary Statement of Principal and Carrying Costs of Term Debt 2007 Test Year
E3-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2007 Test Year
E3-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2007 Test Year
E3-1-5	Unamortized Preference Share Issue Expense Average of Monthly Averages 2007 Test Year
E3-1-6	Fiscal 2007 Calculation of Short-term Unfunded Debt
I-5-15	Energy Probe Interrogatory 15
I-24-41 to 43	VECC Interrogatories 41 to 43
M1-1-1	Impact Statement #1

4.2 Are Enbridge's proposed costs for its debt and preference share components of its capital structure appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
I-1-48	Board Staff Interrogatory 48
I-16-48 to 50	SEC Interrogatories 48 to 50

4.3 Is the proposal to change the equity component of the deemed capital structure from 35% to 38% appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E2-1-1	Utility Business and Financial Risks
E2-1-2	Utility Equity Thickness Financial Risk Update
E2-1-2	Enbridge Gas Distribution Utility Business Risks – Environment
E2-2-1	Calculation of ROE
E3-1-1	Cost of Capital 2007 Test Year
I-2-51	CCC Interrogatory 51
I-9-19	IGUA Interrogatory 19
I-16-51 to 54	SEC Interrogatories 51 to 54
I-24-44 to 57	VECC Interrogatories 44 to 57
I-24-77 to 83	VECC Supplementary Interrogatories 77 to 83
L-9	Evidence of IGUA
L-27-1	Evidence of VECC, CCC and IGUA
L-27-2	Supplementary Evidence of VECC, CCC and IGUA
I-28-1 to 17	Enbridge Gas Distribution Interrogatories of VECC, CCC and IGUA 1 to 17

5 COST ALLOCATION (Exhibit G)

5.1 Is the Applicant's cost allocation appropriate and is it based in its 2006 Board approved methodology?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Subject to the comments below in respect of Issues 6.2, 6.4 and 8.1, and subject to a compliance review of the cost allocation that will be embedded in any rate orders arising from this proceeding, parties accept the Company's evidence in this proceeding about its cost allocation for the Test Year and agree that it is appropriate and consistent with the 2006 Board-approved methodology.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransAlta, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study
I-1-52	Board Staff Interrogatory 52
I-9-20	IGUA Interrogatory 20
I-24-59	VECC Interrogatory 69

5.2 Is the proposal to recover Demand Side Management costs in delivery charges, as opposed to load balancing charges, appropriate?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's proposal, as set out in the evidence, to recover Demand Side Management costs in delivery charges, rather than in load balancing charges.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

G2-3-1	Functionalization of Utility Rate Base
G2-3-2	Functionalization of Utility Working Capital
G2-3-3	Functionalization of Utility Net Investments
G2-3-4	Functionalization of Utility O&M
I-1-53	Board Staff Interrogatory 53

6 RATE DESIGN (Exhibit H)

6.1 Is the proposal to introduce delivery demand charges for Rates 100 and 145 reasonable?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's proposal, as set out in the evidence, to introduce delivery demand charges for Rates 100 and 145.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue except TransAlta and VECC, which take no position.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook
H2-7-1	Annual Bill Comparison
H3-1-1	Revenue Comparison – Current vs Proposed by Rate Class Proposed Methodology
H3-1-2	Proposed Unit Rates by Rate Class
H3-2-1	Proposed Revenue Recovery by Rate Class

H3-3-1	Summary of Proposed Rate Change
H3-4-1	Calculation of Gas Supply Charges by Rate Class
H3-5-1	Detailed Revenue Calculations by Rate Class
H3-6-1	Rate Handbook
H3-7-1	Annual Bill Comparison
I-1-54	Board Staff Interrogatory 54
I-12-1	OAPPA Interrogatory 1

6.2 Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue as follows:

Parties accept the Company's proposal, as set out in the evidence, to annually adjust the monthly customer charges and variable charges to recover the revenue deficiency.

There is no agreement about the Company's proposal to allocate revenue requirement between customer classes. Some parties are concerned that the allocation of the 2007 revenue deficiency as proposed in the Company's evidence results in the collection of revenues greater than allocated costs from Rate 1 and Rate 6 customers based on the Company's filed Revenue to Cost ratios of 1.02 and 1.01 for these rate classes. These parties wish to explore the proposed 2007 revenue requirement allocation in light of the evidence and interrogatory responses on this issue. Other parties support the Company's revenue deficiency allocation and will oppose changes to it.

Participating Parties: All parties participated in the negotiation and settlement of aspects of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada**.**

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook

H2-7-1	Annual Bill Comparison
H3-1-1	Revenue Comparison – Current vs Proposed by Rate Class Proposed Methodology
H3-1-2	Proposed Unit Rates by Rate Class
H3-2-1	Proposed Revenue Recovery by Rate Class
H3-3-1	Summary of Proposed Rate Change
H3-4-1	Calculation of Gas Supply Charges by Rate Class
H3-5-1	Detailed Revenue Calculations by Rate Class
H3-6-1	Rate Handbook
H3-7-1	Annual Bill Comparison
I-1-55	Board Staff Interrogatory 55
I-9-23	IGUA Interrogatory 23
I-12-2	OAPPA Interrogatory 2
I-24-70	VECC Interrogatory 70

6.3 Should the Board approve the contents of the Applicant's Rate Handbook?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue as follows:

Parties agree that it is appropriate for the Board to continue to approve the Company's Rate Handbook, as part of the Rate Order resulting from Rate Case proceedings.

There is no agreement on the Company's proposed Invoice Vendor Adjustment (IVA) charge.

Subject to the issue about the IVA, parties agree that the Rate Handbook as filed should be approved by the Board.

Participating Parties: All parties participated in the negotiation and settlement of this issue except GEC, HVAC, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-14-1	Policies and Regulations of the Company with Respect to Gas Services and Schedule of Service Charges
A1-14-2	Changes to the Schedule of Service Charges
D1-10-2	Gas Distribution Access Rule
H1-1-1	Rate Design
H2-6-1	Rate Handbook
I-19-1	TransAlta Interrogatory 1
I-1-56	Board Staff Interrogatory 56
I-12-3	OAPPA Interrogatory 3
I-24-71 to 73	VECC Interrogatories 71 to 73

6.4 Is the proposed treatment of bundled transportation charges and T-service credit appropriate in light of the Board's Decision in RP-2003-0203 and the settlement agreement?

(Complete Settlement)

There is agreement to settle this issue as follows:

Parties accept the Company's proposed treatment of bundled transportation charges and T-service credits. The final rate increases associated with the implementation of the settlement proposal of the changes in the allocation of upstream transportation charges in EB-2005-0001 will be implemented on October 1st, 2007. Effective October 1, 2007, the upstream transportation charges for all rate classes will recover the appropriate level of upstream transportation costs for all rate classes, so that there will be no over-contribution from Rates 1 and 6 with respect to upstream transportation costs.

The Company will continue to charge and rebate the T-service credit for Ontario T-Service customers. The existing T-Service credit, equal to TransCanada's 100% load factor toll, will continue to be in effect until December 31, 2007. Effective January 1, 2008, the T-Service credit will be based on the weighted average cost of transportation, equal to the unit rate based on total utility transportation costs over total delivery volumes. The Company will treat T-Service credits for Ontario T-Service customers in this manner, as an "off-set", from January 1, 2008 until such time as the Company has a new billing system that permits a different approach. This approach satisfies the Board's directive regarding the Company's obligation to phase-out the T-service credit for Ontario T-Service customers as outlined in the RP-2003-0203 Settlement Proposal.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
I-1-57	Board Staff Interrogatory 57
I-12-4	OAPPA Interrogatory 4

7 CUSTOMER CARE SUPPORT, CUSTOMER CARE SYSTEM, AND OPEN BILL ACCESS

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

D1-12-1	Customer Care - Overview
D1-12-2	Customer Care and Transition Costs
D1-12-3	Customer Care – Benchmarking
I-1-58	Board Staff Interrogatory 58
I-9-17	IGUA Interrogatory 17
I-16-55 to 58	SEC Interrogatories 55 to 58

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

D1-10-1	GDAR
I-1-59	Board Staff Interrogatory 59

7.3 Are the forecast costs of the new CIS system appropriate?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

B1-5-1	CIS Project
I-1-60 to 63	Board Staff Interrogatories 60 to 63
I-9-10	IGUA Interrogatory 10
I-26-11	HVAC Interrogatory 11

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

B1-5-1	CIS Project
D1-12-1	Customer Care – Overview
D1-12-2	Customer Care and Transition Costs
D1-12-3	Customer Care – Benchmarking
D3-2-1	Operating Cost Comparison of Utility Cost and Expenses Budget 2007 and Estimate 2006
I-1-64 to 73	Board Staff Interrogatories 64 to 73
I-16-59	SEC Interrogatory 59

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(No Settlement)

There is no agreement to settle this issue, although the consultative is ongoing.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007
D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006
D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5

I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference

8 OTHER ISSUES

8.1 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the NGEIR (EB-2005-0551) proceeding will be appropriately captured and reflected in this proceeding?

(Complete Settlement)

There is an agreement to settle this issue as follows:

All parties agree that the implications of the Board's decisions in the NGEIR (EB-2005-0551) proceeding have been captured in the Company's filing in this proceeding. This agreement is subject to the stipulation that certain parties have initiated Motions for Review of the Board's decisions in the NGEIR proceeding which, if successful, could require the Company to make consequential adjustments to its rates, including (without limitation) Rate 316.

The Company's obligations under the NGEIR Settlement Proposal pertaining to whether and when an automated solution should be developed and put in place remain in full force and effect.

Every three months the Company will provide to stakeholders a report on the number of customers that have committed to migrate and have migrated to the new unbundled Rates 300 and 315. If, at any time during the Test Year, 20 customers have committed to take EGD's unbundled rates, the Company will undertake a survey, using the least cost approach, to evaluate demand for unbundled Rates 300 and 315, and assess and report on the timing for development of an automated solution and accommodating additional customers through the manual solution within 90 days after the Company's 20th customer has committed to migrate to the new unbundled rates. If, at that time, the Company decides to proceed with a manual solution, it will continue to provide customers with a quarterly report on the status of migration including feedback from customers on the potential for future migration. The parties agree that the Company's costs associated with preparing and administering the survey will be recorded in the 2007 Unbundled Rate Implementation Cost Deferral Account. The parties further agree they will support recovery by the Company of the reasonably incurred survey costs in the 2007 Unbundled Rate Implementation Cost Deferral

Account on the understanding that the Company will seek to have all reasonably incurred costs recovered from large volume customers.

In order to allow customers to take advantage of the new Rate 300 and Rate 315, customers will have the opportunity to migrate to Rate 300 and 315 at all times during the Test Year until the point in time when 20 customers have migrated to the rate 300 series rates. Subject to the conditions of the Company's Early Termination Policy, the Company will permit migrating customers to terminate their bundled rate contracts early, on the understanding that customers will true up any imbalances in their existing contracts as per the provisions of the Company's Early Termination Policy.

If the survey results indicate that significantly more than 20 customers are prepared to commit to migrate, then the Company will undertake to develop an automated solution. If a smaller number of customers are prepared to commit to migrate, then the Company will conduct an analysis comparing the incremental cost of supporting incremental customers' activities and transactions using the manual solution versus the costs of an automated solution. The goal of the analysis will be to determine if it is feasible to expand the manual solution (and at what cost) versus the cost of an automated solution. Should an automated solution be required, the parties agree that the Company record associated costs in the Unbundled Rate Implementation Cost Deferral Account as per the NGEIR Settlement Proposal EB-2005-0551, Ex. S-1-1, p. 33.

If a manual solution permits more than 20 customers to migrate during the Test Year, any such additional spots will be implemented in a manner that is consistent with section 4(g) of the Settlement Agreement in EB-2005-0551 whereby 50% of the additional spots will be allocated to interested customers who will benefit the most from the service from a distribution rate perspective, and 50% of the additional spots will be allocated to interested customers entitled to subscribe for the service on the basis of a lottery system.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue except VECC which takes no position and did not participate in discussion on the issues discussed after the second paragraph above.

Evidence: The evidence in relation to this issue includes the following:

I-19-1 to 3	TransAlta Interrogatories 1 to 3
I-1-78 to 79	Board Staff Interrogatories 78 to 79
I-12-5 to 6	OAPPA Interrogatories 5 to 6

I-20-1	TransCanada Interrogatory 1

8.2 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the DSM (EB-2006-0021) proceeding will be appropriately captured and reflected in this proceeding?

(Complete Settlement)

There is an agreement to settle this issue as follows:

> All parties agree that the implications of the Board's decisions in the DSM (EB-2006-0021) proceeding have been captured in the Company's filing in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

I-1-80 to 81	Board Staff Interrogatories 80 to 81
I-9-21 to 22	IGUA Interrogatories 21 to 22
I-24-76	VECC Interrogatory 76

9 RATE IMPLEMENTATION

9.1 How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

> Parties agree that the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. Parties agree with and support the Company's proposal to recover the full $26.0 million through (i) increased annualized rates for the remainder of the Test Year; and (ii) the use of a rate rider over the nine remaining months of the Test Year to recover the remaining balance of the $26.0 million. Intervenors agree that no issue or

objection will be raised around whether any part of this $26.0 million is unrecoverable because it relates to the time period between January 1, 2007 and April 1, 2007.

There is no agreement as to whether or how the Company can recover any revenue deficiency in excess of $26.0 million.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties except Schools accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-2-1	Application
I-1-82	Board Staff Interrogatory 82
I-16-62 to 53	SEC Interrogatories 62 to 63

9.2 Should the Board set interim rates, effective January 1, 2007, to allow Enbridge to begin to recover its prospective revenue deficiency?

(Complete Settlement)

There is an agreement to settle this issue as follows:

This issue is no longer relevant, since the January 1, 2007 date has passed.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-2-1	Application
I-1-83 to 84	Board Staff Interrogatories 83 to 84
I-16-64 to 65	SEC Interrogatories 64 to 65

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at December 31, 2006 Principal ($000's)	Col. 2 Actual at December 31, 2006 Interest ($000's)	Col. 3 Accounts Agreed to be cleared with Final Rate Order Actual Balances at December 31, 2006 Principal ($000's)	Col. 4 Accounts Agreed to be cleared with Final Rate Order Actual Balances at December 31, 2006 Interest ($000's)	
	Non Commodity Related Accounts for One Time Rate Clearance						
1.	Demand Side Management Account	2006 DSMVA	374.7	(39.4)	-	-	
2.	Demand Side Management Account	2005 DSMVA	697.5	(9.7)	-	-	
3.	Demand Side Management Account	2004 DSMVA	2,013.9	149.1	2,013.9	149.1	
4.	Lost Revenue Adjustment Mechanism	2006 LRAM	-	-	-	-	
5.	Lost Revenue Adjustment Mechanism	2005 LRAM	-	-	-	-	
6.	Lost Revenue Adjustment Mechanism	2004 LRAM	(587.9)	13.6	(587.9)	13.6	
7.	Shared Savings Mechanism	2006 SSMVA	-	-	-	-	
8.	Shared Savings Mechanism	2005 SSMVA	-	-	-	-	
9.	Shared Savings Mechanism	2004 SSMVA	-	-	-	-	
10.	Class Action Suit D/A	2006 CASDA	23,514.2	117.1	-	-	
11.	Deferred Rebate Account	2006 DRA	(1,904.7)	(103.5)	(1,904.7)	(103.5)	
12.	Debt Redemption D/A	2006 DRDA	-	-	-	-	
13.	Ontario Hearing Costs V/A	2006 OHCVA	(612.8)	-	(612.8)	-	
14.	Manufactured Gas Plant D/A	2006 MGPDA	39.0	0.7	-	-	
15.	Electric Program Earnings Sharing D/A	2006 EPESDA	(175.1)	-	-	-	
16.	Corporate Cost Allocation	2006 CCAMDA	623.7	0.6	-	-	
17.	Unbundled Rate Implementation Cost D/A	2006 URICDA	480.5	-	-	-	
18.	Alliance/Vector Appeal Costs D/A	2006 AVACDA	529.2	17.3	-	-	
19.	Total Non Commodity Related Accounts for One Time Rate Clearance		24,992.2	145.8	(1,091.5)	59.2	
	Commodity Related Accounts for One Time Rate Clearance						
20.	2006 Purchased Gas V/A	2006 PGVA	(125,122.4)	(2,237.9)	-	-	a)
21.	2006 Transactional Services D/A	2006 TSDA	(7,508.8)	(15.5)	(7,508.8)	(15.5)	
22.	2006 Unaccounted for Gas V/A	2006 UAFVA	(11,739.1)	-	(11,739.1)	-	
23.	2006 Union Gas D/A	2006 UGDA	(2,919.3)	49.8	(2,919.3)	49.8	
24.	Total Commodity Related Accounts for One Time Rate Clearance		(147,289.6)	(2,203.6)	(22,167.2)	34.3	
25.	Total Deferral and Variance Accounts for One Time Rate Clearance		(122,297.4)	(2,057.8)	(23,258.7)	93.5	
	Non Commodity Related Accounts for Rate Base and Ongoing Rates Treatment						
26.	Gas Distribution Access Rule Costs D/A	2006 GDARCDA	7,923.3	62.1	-	-	b)
27.	Gas Distribution Access Rule Costs D/A	2005 GDARCDA	406.0	29.2	-	-	b)
28.	Gas Supply Risk Management Program D/A	2006 GSRMPDA	691.5	-	-	-	b)
29.	Total Deferral and Variance Accounts for Rate Base and Ongoing Rates Treatment		9,020.8	91.3	-	-	

Note: a) PGVA and related adjustments to be handled as part of April 2007 QRAM.

Note: b) These accounts would be required to be closed into rate base, with associated revenue requirement impacts, pending the hearing review and any eventual Board Approval.

EGD 2007 ADR PROPOSAL
BASED ON REVENUE DEFICIENCY OF $26 MILLION
FINAL

Rate Class	Impacts Relative to July 1, 2006 T-service Rates: Revenue to Cost Ratios 2007	Revenue to Cost Ratios 2006	Over/Under Contribution 2007	Over/Under Contribution 2006	Average Rate Impact T-Service	Impact Relative to January 1, 2007 T-service Rates: Average Rate Impact T-Service	TCPL Phase In Contribution
			$/M	$/M			$/M
1	1.01	1.01	10.35	8.75	2.07%	2.08%	5.01
6	1.01	1.01	5.06	4.19	0.66%	0.67%	4.89
9	0.69	0.69	-0.47	-0.59	6.44%	6.45%	0.00
100	0.97	0.98	-3.48	-2.92	1.91%	1.92%	0.00
110	1.01	1.01	0.38	0.33	-0.85%	-0.84%	0.00
115	0.90	0.90	-4.18	-5.49	0.96%	0.97%	-5.97
135	0.87	0.87	-0.28	-0.33	1.25%	1.25%	-0.60
145	0.97	1.03	-0.49	0.42	1.62%	1.63%	0.00
170	0.81	0.89	-4.98	-3.48	1.76%	1.76%	-3.20
200	0.98	0.98	-0.22	-0.20	4.60%	4.60%	0.00

Note: 2006 and 2007 Over/Under Contributions need to be adjusted by the TCPL phase in contribution amount to reflect the post October 1, 2007 situation.

EGD 2007 ADR PROPOSAL
BASED ON REVENUE DEFICIENCY OF $82.1 MILLION

Rate Class	Revenue to Cost Ratios 2007	Revenue to Cost Ratios 2006	Over/Under Contribution 2007	Over/Under Contribution 2006	Average Rate Impact T-Service	TCPL Phase In Contribution
			$/M	$/M		$/M
1	1.01	1.01	9.35	8.75	6.28%	5.01
6	1.01	1.01	5.42	4.19	4.52%	4.89
9	0.70	0.69	-0.48	-0.59	13.19%	0.00
100	0.98	0.98	-2.98	-2.92	5.48%	0.00
110	1.01	1.01	0.43	0.33	1.04%	0.00
115	0.90	0.90	-4.18	-5.49	1.96%	-5.97
135	0.87	0.87	-0.28	-0.33	2.54%	-0.60
145	0.97	1.03	-0.48	0.42	4.08%	0.00
170	0.82	0.89	-4.82	-3.48	4.24%	-3.20
	0.00		0.00			
200	0.98	0.98	-0.16	-0.20	7.70%	0.00

Note: 2006 and 2007 Over/Under Contributions need to be adjusted by the TCPL phase in contribution amount to reflect the post October 1, 2007 situation.

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 7.5

The issues related to Issue 7.5 ("Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?") have been the subject of the ongoing Open Bill Consultative. Parties have been able to come to an agreement to settle aspects of this issue.

This incomplete settlement, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this incomplete settlement will supersede the reference at page 43 of 47 of the January 29th Settlement Proposal which states that there is no settlement of Issue 7.5.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th Settlement Proposal apply to this Supplementary Settlement Proposal, except for (i) the chart of settled issues, which does not reflect this incomplete settlement of Issue 7.5; and (ii) any references to revenue deficiency and rate impact of the settlement, which would have to be changed to reflect the incremental financial impact of this Supplementary Settlement Proposal.

With that preamble, the following section represents the incomplete settlement that has been agreed upon.

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as follows:

> The parties agree to settle the third party billing component ("Billing Services") of Issue 7.5 Open Bill Access on the basis that the Company can proceed with the Billing Services on the following terms:

1. ***Compliance with Board Directive.*** All parties accept the Company's decision to respond to the Board's directive in EB-2005-0001 in two stages: an interim solution, using the Company's existing CIS, and a comprehensive solution, using the Company's planned new CIS. This settlement constitutes the interim solution until otherwise ordered by the Board in the Board review referred to in #2 below. Subject to the

presentation to the Board of the comprehensive solution, discussed in #2 below, all parties agree that this settlement constitutes an appropriate response to the Board's directive.

2. ***Comprehensive Solution.*** The Company agrees that it will file an application to the Board prior to the end of 2008 proposing the comprehensive Billing Services offering. Such application should include: a) a detailed report on the experience with the interim solution, b) any available consultants' reports with respect to costing and/or market pricing, c) the results of any customer communications activities and any customer or industry surveys, d) minutes and/or reports of the activities of the stakeholder committee referred to in #8 below, and e) the Company's proposal on whether the Billing Services should continue, and if so on what terms. Without limiting the generality of the foregoing, the Company's proposal may include changes to pricing, costing, shareholder incentive, and any other aspects of the Billing Services. In the event that in the Company's application the Company or any party proposes that the Billing Services should not continue, that party must also propose a reasonable transition period to reflect the time required for anyone using the Billing Services to shift to alternate billing arrangements. Nothing in this settlement implies that any party admits to either the relevance or the appropriate weight to be given to any particular evidence in this subsequent application, and all parties will be free to argue as they see fit with respect to any proposed evidence.

3. ***Pricing.*** During the interim period, but at least until December 31, 2008 parties accept the prices proposed by the Company, $0.829 for shared bills and $1.389 for standalone bills. All participants using the Billing Services will pay the same prices for the same services. The parties agree that prices for the Billing Services and any changes from time to time to the rules relating to the OBSDA referred to in #4 below must be approved by the Board.

4. ***Startup Costs.*** The shareholder will bear the startup and bill re-design costs associated with the Billing Services but will be allowed to recover 4 cents/bill from the Open Bill Service Deferral Account (OBSDA) over a two year period until the costs are recovered. The shareholder will not bear the costs associated with adding the Billing Services to the new CIS. The latter costs will be included in the costs of the Billing Services and recovered in revenues from the service.

5. ***Ratepayer Benefit.*** Subject to the shareholder incentive, set forth below, all net benefits, whether through mitigation of common costs, or net profits from the OBA services, will accrue to the benefit of the ratepayers. The Company agrees to include in its 2007 revenue requirement a net benefit of the service of $5.389 million. This number is derived from calculations found in JT.5, as updated to reflect this settlement. To be sure, all parties also agree If the net benefit of the service is greater or less than the amount included in rates, the difference will be credited or debited, as the case may be, to a new variance account, the Open Bill Access Variance Account (OBAVA) and refunded or charged to ratepayers in the following year. The net benefit shall be calculated as the total revenues from Billing Services, less /u

   a. the incremental costs to deliver those services;
   b. the amount referred to in #4 above; and,
   c. the shareholder incentive referred to in #6 below.

6. ***Shareholder Incentive.*** The Company will receive no incentive for Billing Services provided to any affiliate of the Company. For the Billing Services by any other person, the Company will be paid a commission as follows subject to an annual maximum calculated as 50% of the program's net margin:
   a. With respect to any bill on which Direct Energy (which for all purposes of these terms should be interpreted as including any successor to Direct Energy's water heater business) is the sole third party billing entity, $0.02 per bill;

   b. With respect to any bill on which there is any third party billing entity charge other than Direct Energy on the bill:

      i. $0.10 per bill in any month that the Billing Services service has only one active billing entity other than affiliates or Direct Energy;
      ii. $0.15 per bill in any month that the Billing Services service has two active billing entities other than affiliates or Direct Energy;
      iii. $0.20 per bill in any month that the Billing Services service has three active billing entities other than affiliates or Direct Energy;
      iv. $0.25 per bill in any month that the Billing Services service has more than three active billing entities other than affiliates or Direct Energy;

An entity will only be considered an "active billing entity" in any month in which it is billing products or services on at least 500 EGD bills.

7. ***Costing and Pricing Studies:*** The Company agrees that it will retain an independent consultant or consultants to undertake costing and pricing analyses for the Billing Services. The consultant's work will include assistance in determining a market price, and a review and analysis of the incremental and fully-allocated costs of these services. The Company will solicit the stakeholder group's input on the independent consultant(s), and statement of work for those consultant(s), but the Company will retain the right to make the final selection and define the terms of the reference. The cost of these studies will be included in the OBSDA.

8. ***Stakeholder Input.*** The Company will establish a stakeholder committee that includes users of the Billing Services, as well as ratepayer and industry representatives, to review the rules associated with participation in Billing Services. All parties to the agreement will be invited to become members of the stakeholder committee. The committee will meet from time to time as required to consider changes to the rules. Any changes to the rules that materially change the nature of the service will be reviewed by the stakeholder committee and reported to the Board to determine if their approval is required. The stakeholder committee will also be solicited for input into the Company's proposed communications plan, and other issues as they arise.

9. ***Affiliate Participation.*** Affiliates of the Company (including for the purpose of this settlement related parties such as limited partnerships or trusts that are not technically affiliates) may use the Billing Services on the same terms as any other third party biller. However, all parties agree with the principle that the Billing Services should be implemented in a manner that avoids ratepayer and/or consumer confusion, and, to the extent possible, prevents any participant from gaining any unfair market advantage by reason of their association with the utility, if any. The Company agrees that during the interim period it will implement such measures as may be necessary to achieve this principle, including but not limited to including in the Billing Services and enforcing in a commercially reasonable manner the following service rules::

    (a) No person, whether affiliate or otherwise, may use or associate itself with any name or logo on the bill that is the same as, similar to, or confusing with any name or logo that is associated with the Company (e.g. the "Enbridge" name and swirl logo).

(b) No person may use the Billing Services in an abusive or unfair manner in that it deliberately creates the impression that it has a preferred position relative to other market participants because of its relationship with the utility.

Notwithstanding, these restrictions in no way shape or form creates any future precedent to rely upon regarding the use of the Enbridge name or logo.

The parties acknowledge their mutual intention to bring issues with respect to affiliate participation to the stakeholder committee for resolution, but this statement will not limit any rights any party may have, whether under the Affiliate Relationships Code or otherwise, to have disputes resolved in any forum.

10. ***EnergyLink™ Relevance.*** If the Board in this proceeding approves the EnergyLink™ program proposed by the Company, the parties agree that whether a company is an EnergyLink™ participant or not will not affect whether that company can use the Billing Services, nor the rules or conditions under which they use the service.

11. ***Information.*** The Company will develop with input from the stakeholder committee an appropriate customer communication plan specific to Billing Services The Company shall provide to the Board and make available to all parties to this settlement agreement a report that includes revenues from Billing Services, and the costs of the services on a fully-allocated basis,an incremental basis and in a manner when known that is consistent with the methodology recommended in the study noted in paragraph 7, to the extent that this is different .

12. ***Logos and Bill Messaging.*** Logos and bill messaging will be provided to all participants in the Billing Services at no charge to facilitate entry of new users and help consumers differentiate the various parties with amounts billed on the EGD bill. Any provision of logos and bill messaging for the Billing Services will apply in the same manner to commodity vendors using the ABC Services for a reasonable charge, but commodity messaging will not be allowed unless EGD or one of its affiliates starts to market system gas.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Energy Probe, IGUA, OAPPA, Superior, TransAlta, TransCanada and Union Gas,

Approval: All participating parties accept and agree with the proposed settlement of this issue except that GEC and Pollution Probe reserve the right to pursue in the Hearing whether the Board should order that third parties not be allowed to use the Billing Services for the billing of specific products on the basis of their environmental attributes.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007
D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006

D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
D1-11-29	Third Party Access to the Bill Customer Communication Plan
D1-11-30	Billing Insert Customer Communication Plan
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5
I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference
JT1-JT22	Undertakings from January 10, 2007 Technical Conference

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 7.5

The issues related to Issue 7.5 ("Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?") have been the subject of the ongoing Open Bill Consultative. Parties have been able to come to an agreement to settle aspects of this issue.

This incomplete settlement, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this incomplete settlement will supersede the reference at page 43 of 47 of the January 29th Settlement Proposal which states that there is no settlement of Issue 7.5.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th Settlement Proposal apply to this Supplementary Settlement Proposal, except for (i) the chart of settled issues, which does not reflect this incomplete settlement of Issue 7.5; and (ii) any references to revenue deficiency and rate impact of the settlement, which would have to be changed to reflect the incremental financial impact of this Supplementary Settlement Proposal.

With that preamble, the following section represents the incomplete settlement that has been agreed upon.

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(Incomplete Settlement)

There is an agreement of some parties to settle aspects of this issue, as follows:

Proposed Billing Insert Settlement

The parties agree to settle the billing insert ("Insert Service") component of Issue 7.5 Open Bill Access on the basis that the Company can proceed with the Insert Service on the following terms:

1. ***Compliance with Board Directive.*** All parties accept the Company's decision to respond to the Board's directive in EB-2005-0001 in two stages: an interim solution, using the Company's existing CIS, and a comprehensive solution, using the Company's planned new CIS. This settlement constitutes

the interim solution until otherwise ordered by the Board in the Board review referred to in #2 below. Subject to the presentation to the Board of the comprehensive solution, discussed in #2 below, all parties agree that this settlement constitutes an appropriate response to the Board's directive as it pertains to bill inserts.

2. ***Comprehensive Solution.*** The Company agrees that it will file an application to the Board prior to the end of 2008 proposing the comprehensive Billing Insert Service offering. Such application should include: a) a detailed report on the experience with the interim solution, b) any available consultants' reports with respect to costing and/or market pricing, c) the results of any customer communications activities and any customer or industry surveys, d) minutes and/or reports of the activities of the stakeholder committee referred to in #8 below, and e) the Company's proposal on whether the Insert Service should continue, and if so on what terms. Without limiting the generality of the foregoing, the Company's proposal may include changes to pricing, costing, shareholder incentive, and any other aspects of the Insert Service. Nothing in this settlement implies that any party admits to either the relevance or the appropriate weight to be given to any particular evidence in this subsequent application, and all parties will be free to argue as they see fit with respect to any proposed evidence.

3. ***Pricing.*** For the interim period of 2007 and 2008, the Company agrees to reduce the minimum bids for bill inserts by one cent resulting in an average insert charge of 4 cents. For greater clarity, there shall be no right of first refusal for parties using the Company's Insert Service. The parties agree that prices for the Insert Service, and any changes thereto from time to time, must be approved by the Board.

4. ***Costing and Pricing. T***he Company agrees that it will retain an independent consultant to undertake a costing and pricing analysis for the Bill Insert Service for the comprehensive period. The consultant's work will include assistance in determining a market price, and a review and analysis of the incremental and fully-allocated costs of these services for the new CIS. The Company will solicit the stakeholder group's input on the independent consultant, and statement of work for that consultant, but the Company will retain the right to make the final selection and define the terms of the reference. The cost of this study will be included in the Open Bill Service Deferral Account (OBSDA).

5. ***Startup Costs.*** The shareholder will record the startup costs associated with the Insert Service in 2007 in the OBSDA. The startup costs associated with

adding the Insert Service to the new CIS will be included in the costs of the Insert Service and recovered in revenues from the service.

6. ***Ratepayer Benefit.*** The Company agrees to record the costs and revenues from the Insert Service in 2007 in the OBSDA and that the net proceeds will be shared 50/50. The parties agree that the shareholder incentive mechanism for Insert Service may need to be revised after the interim period and after the cost/price review to be consistent with the Board's rules for natural gas incentive regulation.

7. ***Inserts.*** Bill inserts would be allowed as proposed by EGD but revised to limit the number of external inserts to five (5) when safety inserts are scheduled. In all months, two inserts would be reserved for parties wishing to purchase bill inserts in a limited geographic area based on price per insert bidding.

8. ***Stakeholder Input.*** The Company will establish a stakeholder committee that includes users of the Insert Service, as well as ratepayer and industry representatives, to review the rules associated with participation in the Insert Services. All parties to the agreement will be invited to become members of the stakeholder committee. The committee will meet from time to time as required to consider changes to the rules. Any changes to the rules that materially change the nature of the service will be reviewed by the stakeholder committee and reported to the Board to determine if their approval is required. The stakeholder committee will also be solicited for input into the Company's proposed communications plans, and other issues as they arise. To ensure that consumer interests are being addressed, EGD will conduct focus groups and customer surveys on inserts as soon as possible in 2007 and report the findings to the stakeholder committee to determine if remedial action is required. EGD will also prescreen insert users and review the content of their bill inserts to ensure proper use of its billing envelope.

9. ***Problem Resolution.*** If the revised bidding and allocation processes restrict access in three consecutive months or the number of customer complaints on inserts increases significantly in the first two months of operation, the stakeholder committee would be convened to address the concern(s), and if the problem cannot be resolved within two (2) additional months that aspect of the Insert Service would be discontinued until the problem is addressed.

10. ***Affiliate Participation.*** Affiliates of the Company (including for the purpose of this settlement related parties such as limited partnerships or trusts that are

not technically affiliates) may use the Insert Service on the same terms as any other third party biller. However, all parties agree with the principle that the Insert Service should be implemented in a manner that avoids ratepayer and/or consumer confusion, and, to the extent possible, prevents any participant from gaining any unfair market advantage by reason of their association with the utility, if any. The Company agrees that during the interim period it will implement such measures as may be necessary to achieve this principle, including but not limited to including in the Insert Services and enforcing in a commercially reasonable manner the following service rules::

(a) No person, whether affiliate or otherwise, may use or associate itself with any name or logo in the billing envelope that is the same as, similar to, or confusing with any name or logo that is associated with the Company (e.g. the “Enbridge” name and swirl logo).

(b) No person may use the Insert Service in an abusive or unfair manner in that it deliberately creates the impression that it has a preferred position relative to other market participants because of its relationship with the utility.

Notwithstanding, these restrictions in no way shape or form creates any future precedent to rely upon regarding the use of the Enbridge name or logo.

The parties acknowledge their mutual intention to bring issues with respect to affiliate participation to the stakeholder committee for resolution, but this statement will not limit any rights any party may have, whether under the Affiliate Relationships Code or otherwise, to have disputes resolved in any forum.

11. ***EnergyLink^{TM} Relevance.*** If the Board in this proceeding approves the EnergyLink^{TM} program proposed by the Company, the parties agree that whether a company is an EnergyLink^{TM} participant or not will not affect whether that company can use the Insert Service, nor the rules or conditions under which they use the service, subject to the restriction on use of the Enbridge name and logo as described in Item 10 above.

12. This agreement should not be construed as a settlement of any aspect of issue 3.4, including but not limited to, arguments to restrict the Company’s ability to promote EnergyLink^{TM} by bill insert or otherwise. Notwithstanding, the Company agrees to provide a schedule of EnergyLink^{TM} inserts on an annual basis, as part of the Binding Request for Bids process.

13. ***Commodity Marketing.*** Commodity bill inserts and marketing will not be allowed in the billing envelope unless EGD or one of its affiliates receives OEB approval to promote and/or market system gas commodity, in which case retailers, marketers and vendors will be allowed to promote and/or market their commodity offers through the Insert Service.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Energy Probe, IGUA, OAPPA, TransAlta, TransCanada and Union Gas,

Approval: Enbridge Gas Distribution, Direct Energy, OESLP and Union Energy accept and agree with this proposed settlement. HVAC, VECC and Schools do not agree with the proposed settlement. CCC opposes the proposed settlement in order that it may be permitted to pursue cross-examination on the issue. GEC and Pollution Probe reserve the right to pursue in the Hearing whether the Board should order that third parties not be allowed to use the Billing Services for the billing of specific products on the basis of their environmental attributes. Superior opposes the proposed settlement on the principle that it is not supportive of a settlement position that would allow for the Company to promote system gas through billing inserts as contemplated in Paragraph 13.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
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D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007

D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006
D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
D1-11-29	Third Party Access to the Bill Customer Communication Plan
D1-11-30	Billing Insert Customer Communication Plan
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5
I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference
JT1-JT22	Undertakings from January 10, 2007 Technical Conference

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 6.3

The Settlement Proposal filed as Exhibit N1, Tab 1, Schedule 1, which was approved by the Board on January 29, 2007 (the "January 29th, 2007 Settlement Proposal"), notes at page 39 of 47 that Issue 6.3 was an Incomplete Settlement. Specifically, there was no agreement on the Company's proposed Invoice Vendor Adjustment (IVA) charge. Discussions have continued in respect of the IVA charge and Parties have been able to come to an agreement to settle outstanding issues relating to the IVA charge.

If this Supplementary Settlement Proposal for the IVA charge is approved by the Board, it will be added to the January 29th, 2007 Settlement Proposal, and the provisions of this Supplementary Settlement Proposal will supersede the reference at page 39 of 47 of the January 29th, 2007 Settlement Proposal which states that there is No Settlement in respect of the IVA charge.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th, 2007 Settlement Proposal apply to this Supplementary Settlement Proposal, except for the chart of settled issues, which does not reflect the complete settlement of Issue 6.3.

With this preamble, the following section represents the complete settlement that has been agreed upon.

6.3 Should the Board approve the contents of the Applicant's Rate Handbook?

(Complete Settlement)

There is an agreement to settle aspects of this issue, as follows:

The parties agree that:

1. The IVA charge by the Company will equal 0.65% of the absolute dollar value of the adjustment. Parties agree that this IVA charge is an interim measure that will apply from June 1, 2007 to December 31, 2007, and is without prejudice to any Party proposing an alternative IVA charge commencing January 1, 2008.

2. The Company will consult with interested parties and will consider the merits of bringing forward a different fee structure for a cost-based IVA charge. The Company will seek approval from the OEB for the new IVA charge, to be effective January 1, 2008.

3. Parties agree that the IVA charge is designed to only recover the costs incurred by the Company to provide this service. As a result, Parties agree that there is no need to adjust the revenue deficiency as a result of forecast IVA charge revenues and costs. The Company will provide parties with a summary of 2007 IVA charge revenues and costs subsequent to December 31, 2007.

***Participating Parties*:** All parties participated in the negotiation and settlement of this issue except Energy Probe, GEC, HVAC, LIEN, OAPPA, Pollution Probe, SEC, Superior, TransCanada, TransAlta, Union Energy and Union Gas.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue. Without limiting the generality of the Introduction to the Settlement Proposal, VECC's acceptance of this proposed settlement is without prejudice to it proposing that IVA charges be reviewed as part of the Board's generic review of the QRAM/System Gas. CCC, HVAC, IGUA, Energy Probe, SEC, and Union Energy take no position.

Evidence: The evidence in relation to this issue includes the following:

D1-10-2, plus attachment
Tr. 5, pp. 68, 73-74

Gas Distribution Access Rule

SETTLEMENT PROPOSAL FOR CUSTOMER CARE AND CUSTOMER INFORMATION SYSTEM ("CIS") ISSUES

I. PREAMBLE

The following issues related to Enbridge Gas Distribution's Customer Care O&M and Customer Information System ("CIS") capital budgets, and related matters, have been among the subjects addressed as part of the ongoing Customer Care/CIS Consultative:

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision? (D1-12-3)

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account? (D1-10-1, p. 2/AppA)

7.3 Are the forecast costs of the new CIS system appropriate? (B1-5-1, p. 3)

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs? (D1-12-1, p. 2 and D3-2-1, p. 1)

As set out below, parties have been able to come to an agreement to settle these issues, as well as other matters related to Customer Care and CIS.

All aspects of this Supplementary Settlement Proposal are subject to approval by the Board. The parties to the settlement all agree that this Supplementary Settlement Proposal is a package: the individual aspects of this agreement are inextricably linked to one another and none of the parts of this settlement are severable. As such, there is no agreement among the parties to settle any aspect of the issues addressed in this Supplementary Settlement Proposal in isolation from the balance of the issues addressed herein. The parties agree, therefore, that in the event that the Board does not accept this Supplementary Settlement Proposal in its entirety, then (in accordance with the Board's Settlement Conference Guidelines) the Board will reject the

Supplementary Settlement Proposal in its entirety and proceed to hearing on all of the issues listed above.

This Supplementary Settlement Proposal, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this Supplementary Settlement Proposal will supersede the references at pages 41 and 42 of the January 29th Settlement Proposal which state that there is no settlement of Issues 7.1 to 7.4.

If approved by the Board, this Supplementary Settlement Proposal will reduce the Company's revenue deficiency for the Test Year by approximately $24.2 million, from the $52.1 million remaining as the revenue deficiency in the Company's Application, after the Settlement Proposal (Ex. N1-1-1) revenue deficiency of $29.9 million was approved by the Board on January 29, 2007 (with $26.0 million thereof recoverable in interim rates effective April 1, 2007). The remaining revenue deficiency at issue in the Company's Application is now about $26.1 million[1], taking into account the fact that parties are agreeing in this Supplementary Settlement Proposal that the Company can recover a revenue deficiency of approximately $1.8 million in respect of customer care and CIS costs in the Test Year.[2] This $1.8 million Customer Care revenue deficiency, which is described below in more detail, is the result of extra costs from customer growth, offset by a reduction in bad debt costs.

Finally, although it is not set out expressly in the sections that follow, the parties agree that, as part of this settlement package, Issue 7.2 is resolved because the Regulatory Asset Account application is no longer necessary. The parties also agree that, in response to Issue 7.1, the Company has filed those materials stipulated in the Board's EB-2005-0001 Decision that are currently available. There are, however, some agreements associated with the Company's move away from CustomerWorks Limited Partnership ("CWLP"), including transition agreements with Accenture Business Services for Utilities ("ABSU")[3], that are not completed. Accordingly, at this time Issue 7.1 is partially resolved and the parties expect that it will be completely resolved when those agreements are finalized and filed.

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[1] Note that this does not include any impact of Supplementary Settlement Proposals related to bill access and IVA charges.

[2] The $1.8 million deficiency to be recovered for Customer Care is derived by starting with the customer care deficiency of $26 million, set out at lines 2 and 3 of the Table at Ex. N1-2-2, p. 2, and then subtracting $24.2 million, which is the agreed-upon revenue deficiency reduction that would result from approval of this Supplementary Settlement Proposal.

[3] For the purposes of this Supplementary Settlement Proposal, both Accenture Business Services for Utilities and Accenture Inc. will be referred to as "ABSU".

With that preamble, the following represents the settlement that has been agreed upon.

II INTRODUCTION

Beginning in 2000, Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company") entered into a series of arrangements whereby CIS and Customer Care services were acquired through a related company, Enbridge Commercial Services Inc. ("ECSI"). ECSI subsequently entered into a limited partnership arrangement with Terasen Inc., CWLP, for the purpose of providing customer related business support and information technology services to utilities. Enbridge Gas Distribution entered into a new Customer Care services agreement with CWLP and consented to ECSI's assignment of its CIS service agreement to CWLP, both effective from January 1, 2002. In August 2002, CWLP entered into an agreement in writing with ABSU, hereinafter referred to as the "Program Agreement", whereby CWLP transferred certain assets and all operating personnel to ABSU, and ABSU agreed to provide Customer Care services, including CIS hosting services, on behalf of CWLP to Enbridge Gas Distribution and other utilities for the period that could be as long as 2002 to 2011 (inclusive) for amounts detailed in a Schedule to the Program Agreement. Since 2002, pursuant to the Program Agreement, ABSU has been performing the Customer Care and CIS services for the Company on behalf of CWLP.

A portion of the fees which the Company has paid to CWLP/ECSI to acquire CIS and Customer Care services was paid by CWLP/ECSI, ultimately, to Enbridge Gas Distribution's parent or other affiliates.

In a series of rate cases, the Intervenors expressed their objection to these arrangements, arguing that ratepayers should only be required to pay for CIS and Customer Care services at a market price or, failing a competitive process, at the cost of any affiliate, or related company, providing the services, including an appropriate return on such an endeavour. In the 2006 rate case decision, the Board agreed that what ABSU was paid to provide the services to Enbridge Gas Distribution for Customer Care and CIS services was relevant to the determination of the market prices for the services. The Board ultimately used CWLP revenue from Enbridge Gas Distribution, expressed as a proportion of CWLP's total revenues, as a tool to derive CWLP overearnings attributable to Enbridge Gas Distribution, and then, using the utility allowed return, the Board determined the amount recoverable from Enbridge Gas Distribution's ratepayers. The Board, in decisions in rate cases beginning in 2003 and culminating in Enbridge Gas Distribution's 2006 rates case, urged the Company to obtain CIS and Customer Care services by direct competitive tender which, in the Board's view, should exclude the right of first refusal in favour of CWLP.

Following the Decision with Reasons of the Board in EB-2005-0001, Enbridge Gas Distribution undertook to do the following:

1. Acquire a new Customer Information System (CIS) through a direct competitive tender;

2. Acquire Customer Care services through a direct competitive tender.

Enbridge Gas Distribution also convened a consultative process (the "Consultative") through which Intervenors could monitor and comment on these procurement processes. In light of the concern which Intervenors had, in past rate cases, expressed about Enbridge Gas Distribution's arrangements for acquiring CIS and Customer Care Services, the Intervenors wanted to be assured that the procurement processes were consistent, in all respects, with accepted industry standards, and that the arrangements resulting from the procurement processes will not result in amounts being paid by Enbridge Gas Distribution to CWLP, Enbridge Gas Distribution's affiliates, or its parent. Enbridge Gas Distribution convened the Consultative in part to give the Intervenors those assurances. To further ensure that the Consultative could achieve its goals, Intervenors were given access to independent expertise to advise them on the procurement processes and the results therefrom.

Through the Consultative, the Company informed Intervenors that CWLP has not indicated any intention to exercise its right of first refusal in respect of the new Customer Care or CIS services. CWLP/ABSU have now committed to include a clause in the transition agreements associated with the move to new service providers that will waive CWLP's right of first refusal when the transition agreements are signed.

The Company represents that, apart from the payments to be made by the Company to CWLP up to April 1, 2007, no more than $8.34 million in aggregate will be paid by any person to CWLP, ECSI, EI or any other related entity in relation to any Customer Care or CIS services included within this agreement and provided to Enbridge Gas Distribution by any person during the course of this agreement.

As a result of the work of the Consultative, Enbridge Gas Distribution and the Intervenors have been able to reach agreement on certain aspects of the procurement processes completed to date. The work of the Consultative is described in the pre-filed evidence of Mario Bauer, filed as Exhibit L-2.

The procurement processes will not be completed, with the selection of a new CIS and a new Customer Care service provider, until mid 2007. As a result, the cost of the new CIS and of the new Customer Care service provider cannot be estimated at this time. In addition, the prudence and cost consequences of the CIS and Customer Care arrangements cannot be determined until those arrangements have been finalized, which is expected to be in the first half of 2007. As well, the new CIS will not become operational until June 2009 and it is only at that time that final costs for the new CIS will be known. Finally, the shortlisted bidders for Customer Care services include ABSU and a third party, so there is the potential that a new service provider, other than ABSU, will be selected. The introduction of a Customer Care service provider, other than ABSU, will involve transition arrangements with ABSU and others in both 2007 and 2008, and the costs consequences and upper limits of those costs have been estimated. Final estimates of such costs cannot be made until a later date.

Within these practical constraints, the parties have settled Issues 7.1 through 7.4, which are the Customer Care and CIS issues in this EB-2006-0034 proceeding. The settlement necessarily reflects the fact that certain aspects of the CIS and Customer Care arrangements, including the final costs and contract terms, will not be known until later in 2007.

The parties have agreed that a placeholder amount will be used to establish the revenue requirement for Customer Care costs for 2007. The placeholder chosen is the cost-per-customer set by the Board in the EB-2005-0001 Decision, at $49.58. As a result of this settlement, the total Customer Care budget to be recovered in rates for 2007, including all internal and external costs (except for bad debt), and including all revenue requirement impacts of CIS, will be $90.8 million, plus an amount of $15.1 million representing the provision for uncollectible accounts.

The settlement includes provision for a “true-up” process to adjust the revenue requirement to reflect the prudent and reasonable forecast amounts resulting from the procurement processes, and to reflect the agreed-upon recovery of certain “transition” costs.

The parties believe that a six-year term, covering the period 2007 through 2012 inclusive, is the appropriate term over which to calculate the revenue requirement relating to Customer Care and CIS. The expected costs of CIS and Customer Care during that period may fluctuate year over year. The parties agree that the annual amounts included in rates should be smoothed, over the 2007-2012 term, to avoid swings in rates. The effect of the true-up process is (a) to capture any variance between the 2007 placeholder for Customer Care and CIS revenue requirement of $90.8 million and the normalized revenue requirement for 2007 and pay that variance to, or recover it from, the ratepayers in the 2008-2012 period, and (b) establish the component of the Company’s revenue requirement relating to Customer Care and CIS (except bad debt) for the period 2007-2012, and smooth the rate impacts of that component over that period.

To reflect the settlement the parties have agreed upon a template (the “Template”), which sets out all of the relevant categories of expenses over the 2007 to 2012 period that relate to Customer Care and CIS (except for bad debt costs). The costs in a number of those categories can be established today, and the parties have therefore agreed to those amounts. However, some costs to be set out in the Template must be determined when the contract prices and other costs are known. For those costs, the parties have agreed to the parameters under which those costs will be calculated or forecast and then included in the true-up calculation.

As the parties anticipate the possibility of an incentive regulation ("IR") regime, the terms of which are expected to be established later in 2007, they believe that the true-up should occur at a time when the IR formula for the Company has been established. Once the contract for Customer Care services has been signed, and the terms of IR are known, which is expected to be in the fall of 2007, the parties have agreed that the true-up should take place, in accordance with the true-up rules set out in this Settlement Proposal and Appendix. Parties agree that adjustments may need to be made to aspects of this agreement in the event that the IR regime that, for the purposes of calculation, was assumed by the parties in creating the Template – ie. a price cap IR regime of five years in duration, beginning January 1, 2008 - is not established. Adjustments may need to be made to the normalization approach set out in the True-Up Rules (which are attached) to make it compatible with the IR model and formula that is approved for Enbridge Gas Distribution. Any such adjustments would not affect the total revenue requirement to be recovered over the term of this agreement, but they may impact upon the amount to be recovered in each year of the agreement under the normalization approach that is used.

Finally, the parties agree that the Consultative will continue to monitor the completion of the procurement process, up to and including reviewing the final terms of the contracts, and thereafter, the implementation of the CIS and Customer Care arrangements, which the parties agree will be no later than six months after the in-service date for the new CIS. As has been the case to date, the Intervenors involved in the Consultative agree that they will raise any concerns about the ongoing process, and the outcomes from that process, as soon as they have sufficient information to identify and communicate those concerns. If the Intervenors involved in the Consultative believe that they are not receiving sufficient information, they will advise the Company immediately. The parties agree that the Consultative will continue to work in a timely, responsive and reasonable manner until its mandate is completed. Finally, the parties agree that all costs of the Consultative, for as long as it continues, will be fully recoverable from ratepayers. Costs of the Consultative that are incurred in 2007 will be included in the already established 2007 Ontario Hearings Costs Variance Account (2007 OHCVA). Parties agree to support the continuation of appropriate deferral accounts in future years for the recording and disposition of future costs of the Consultative, unless these costs are included in the Company's regulatory O&M budget during the IR term.

II TERMS OF SETTLEMENT

Against that background, the parties have agreed as follows:

(A) ***2007 O&M Customer Care costs***

As noted above, certain of the anticipated costs associated with Customer Care during the period 2007 through 2012 will not be known until RFP processes currently being carried out by the Company are completed and market prices are identified. As a result, revenue requirement will be established for 2007 using a placeholder to calculate the Customer Care costs. The placeholder will be the Board-approved 2006 cost per customer of $49.58, times the projected number of customers in 2007, 1,831,283, to get a total Customer Care placeholder of $90.8 million for 2007.

The parties agree that projected bad debt costs (Provision for Uncollectible Accounts) of $15.1 million as filed by the Company shall be recoverable in rates in 2007. This agreement does not deal with bad debt costs beyond 2007; as a result, bad debt costs are not included in the True-Up calculation. For the period from 2008 to 2012, bad debt costs will be dealt with by the Board along with other O&M costs, separately from other Customer Care costs which are the subject of this agreement, in such other proceeding or proceedings as the Board may determine.

For the purposes of settlement, the Customer Care placeholder of $90.8 million plus bad debt costs of $15.1 million will replace the amounts in the Company's Application and pre-filed evidence which total $130.1 million, and are comprised of $101.6 million for Customer Care and CIS Service Charges, $3.4 million for Customer Care Internal Costs, $15.1 million for Provision for Uncollectibles and $10.0 million for transition costs (see Exhibit D1-2-1, p. 3, Table 1, lines 2 to 4 and Ex. D1-1-1, p. 1, Table 1, line 3). These internal and transition costs are addressed in the True-Up Rules which are attached as Appendix A.

As a result, the settlement of this item will reduce the Company's revenue deficiency for the Test Year by approximately $24.2 million, from the $52.1 million remaining as the revenue deficiency in the Company's Application, after the Settlement Proposal (Ex. N1-1-1) revenue deficiency of $29.9 million was approved by the Board on January 29, 2007 (with $26.0 million thereof recoverable in interim rates effective April 1, 2007). The remaining revenue deficiency at issue in the Company's Application is now about $26.1 million, taking into account the fact that parties are agreeing in this Supplementary Settlement Proposal that the Company can recover a revenue deficiency of approximately $1.8 million in respect of customer care and CIS costs in the Test Year (the amount that is the difference between the 2006 Board-approved budget of $104.1 million and the $105.9 million total amount for 2007 for Customer Care, CIS and bad debt costs). This $1.8 million Customer Care revenue deficiency can be derived by accounting for customer growth in F2007 over the previous year (the $49.58 placeholder is multiplied by 46,228, which is the forecast number of new customers in 2007) and adjusting for a reduction of $500,000 in bad debt costs, as compared to F2006.

(B) 2007 Capital costs related to CIS

The parties agree that any capital spending by the Company during the 2007 Test Year related to the new CIS shall be in addition to the Company's overall Board-approved capital budget of $300 million plus the costs of the Portlands Energy Centre LTC. This is consistent with the language in Issue 1.1 of the Settlement Proposal in this EB-2006-0034 proceeding, which was approved by the Board on January 29, 2007 and which stated that "[p]arties have reached a global settlement of all 2007 Rate Base issues, except for issues related to the capital budget for the new CIS system" (Ex. N1-1-1, p. 13). No capital expenditures in 2007 relating to the new CIS will be closed to rate base in 2007, and the new CIS will have no impact on 2007 rates.

(C) Selection process for new CIS and Customer Care service providers and Transition Plan

As explained above in the Introduction section, it is anticipated that the selection of a new CIS and a new Customer Care service provider will occur in the second quarter of 2007, when the associated RFP processes are completed.

Once selections are made, contracts will have to be negotiated and settled with the chosen parties. At that time, some of the expected costs of the new CIS, and payments to be made to the new Customer Care service provider, will be established between Enbridge Gas Distribution and the service providers through contractual arrangements. The Consultative will continue to function until the completion of the procurement process, the implementation of those CIS and Customer Care arrangements and the completion of the true-up process described below. The Consultative will be involved with monitoring the selection process and reviewing the terms and prudence of the resulting contracts, including the reasonableness of their costs. Parties agree that the Consultative will continue to work in a timely, responsive and reasonable manner until its mandate is completed.

The selection processes for both the CIS and the Customer Care services RFPs are underway. At this point, the remaining shortlisted bidders for the Customer Care services include ABSU and a third party. The remaining shortlisted bidders for the system integrator component of the new CIS include ABSU and a third party. The parties have agreed that for the time period from January 1, 2007 to March 31, 2007, CWLP will continue to provide CIS and Customer Care services to Enbridge Gas Distribution. For the period commencing April 1, 2007 and concluding no later than September 30, 2008, Enbridge Gas Distribution is making arrangements with ABSU to provide the CIS and Customer Care services directly to Enbridge Gas Distribution, at least until the potential transition to new service providers is complete.

There are two types of transition costs addressed in this Supplementary Settlement Proposal: CIS transition costs and Customer Care transition costs.

The parties acknowledge and agree that all transition costs with respect to the new CIS are included in the $118.7 million capital cost of the new CIS (discussed below), whether or not ABSU is awarded the system integrator component of that project.

The parties further acknowledge and agree that, in the event that ABSU is chosen as the Customer Care service provider, there will be no transition costs associated with Customer Care services. In the event that the third party is chosen as the Customer Care service provider, then there will be transition costs associated with the move to the new service provider. Enbridge Gas Distribution has prepared, and has shared with the Consultative, a Transition Plan that sets out how Customer Care may be transitioned to a new service provider. The parties agree that there will be costs associated with any such transition, and that those costs are recoverable in the manner and amounts described in detail in the True-Up Rules at Appendix A. The Company agrees that it will keep the transition costs, and the transition time period, to a reasonable level while managing the risks associated with transition and ensuring that the ongoing provision of Customer Care services meets OEB-mandated service levels. In this regard, the Company agrees that while the maximum time period for transition to a new Customer Care service provider will be 18 months from April 1, 2007, it will make best efforts to shorten that time period. The Company will ensure that its arrangements with ABSU will allow the Company to direct ABSU to cease the provision of some or all Customer Care transition services before the end of 18 months and, as a result, to reduce the transition costs payable by Enbridge Gas Distribution to ABSU.

(D) <u>The True-Up process and Revenue Requirement for 2008 to 2012</u>

(i) Overview

The parties agree that, on a date (the "True-Up Time") that is the later of (a) the date when the Company's Customer Care RFP is completed and the contract is signed, and

(b) the date when the Board's decision with respect to the duration, rules and formulae for IR that relate to Enbridge Gas Distribution is released, the parties will calculate a true-up and smoothing for the Customer Care amounts for 2007 to 2012, using the specific rules set forth in Appendix A to this Settlement Proposal (the "True-Up Rules").

As set out in more detail below in Appendix A, the amount of the Customer Care costs that are projected to be incurred by the Company during the 2007 to 2012 period, and which the Company will recover in rates, will be determined by the parties at the True-Up Time in accordance with the criteria specified in the True-Up Rules. The components of the Customer Care costs and revenue requirement are itemized in the "Customer Care and CIS Settlement Template" (already defined as the "Template"), which is attached to Appendix A.

It is the intention of the parties that the True-Up process will be used to determine the Customer Care amount for 2007 (the "Normalized 2007 Customer Care Revenue Requirement") that, when adjusted using the True-Up Rules for each year until 2012, will allow the Company to fully recover in rates the costs incurred in providing Customer Care services (including CIS) during the period from 2007 through 2012.

In the event that the parties are unable to agree on the amount of any component of the Normalized 2007 Customer Care Revenue Requirement or any number to be included in the Template, other than those numbers that are fixed by the terms of this agreement, then parties agree that the unresolved dispute will be determined by the Board in accordance with the criteria specified in the True-Up Rules. Specifically, if the parties have not agreed to the Normalized 2007 Customer Care Revenue Requirement within sixty days of the True-Up Time, they shall list the components of the calculation that are in dispute, and provide that list to the Board for determination in accordance with the criteria specified in the True-Up Rules.

The outcome of the True-Up process will be the subject of a separate application to the Board. That application will include, for Board approval, all numbers that are agreed upon and set in accordance with the True-Up Rules, as well as the list of the items remaining at issue to be determined by the Board.

(ii) 2007 Customer Care Variance Account

At True-Up Time, the Company will calculate the difference (the "2007 Customer Care Revenue Requirement Variance") between that amount of revenue requirement that is, pursuant to the True-Up Rules, recoverable for 2007 Customer Care costs (the Normalized 2007 Customer Care Revenue Requirement) and the placeholder of $90.8 million, and will credit or debit the 2007 Customer Care Revenue Requirement

Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012. The 2007 Customer Care Variance Account will be cleared in accordance with the True-Up Rules.

In order for effect to be given to this provision of this Settlement Proposal, parties agree that it is appropriate that a 2007 Customer Care Variance Account be created, and continued until 2012.

(iii) Revenue requirement for Customer Care costs between 2008 and 2012

The revenue requirement that the Company will be entitled to recover each year in respect of Customer Care costs (including CIS but not including bad debt) from 2008 to 2012 shall be the Normalized 2007 Customer Care Revenue Requirement, as adjusted for each year from 2008 to 2012 (inclusive) by the Incentive Regulation formula. The intention of the parties is that this will result in a relatively stable revenue requirement for CIS and Customer Care services over a five year period.

As set out above, and explained in the True-Up Rules, the "Normalized 2007 Customer Care Revenue Requirement" will be the amount that, when adjusted according to the True-Up Rules (including the rules for IR described as part of the True-Up Rules) for each year until 2012, will allow the Company to fully recover in rates the total of all forecast prudent and reasonable Customer Care costs (including CIS but not including bad debt) for the period from 2007 through 2012.

The parties agree that all O&M costs associated with Customer Care (except for bad debt costs), including O&M relating to the Company's proposed new CIS, are included in the calculation of Normalized 2007 Customer Care Revenue Requirement and therefore will be properly recovered in rates during the period 2007 through 2012 through the operation of the True-Up Rules.

The Company agrees that, once the outstanding items on the Template are determined, and completed, and, as a result, the Normalized 2007 Customer Care Revenue Requirement is established, the Company will not seek any adjustment to its rates or revenue requirement that is directly or indirectly based on changes in Customer Care costs during the term of this agreement. Intervenors similarly agree that they will not seek adjustments to the Company's rates or revenue requirement that is directly or indirectly based on changes in Customer Care costs. As expressed above, bad debt costs are not included as part of the Customer Care costs that are the subject of this agreement from 2008 to 2012.

Notwithstanding the limitations expressed in the preceding paragraph, the parties agree that in the event that new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period up to and including 2012, and those requirements materially change the level of Customer Care costs, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the agreement will be established at the IR proceeding. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the IR rules that apply to the Company.

In order to give effect to certain aspects of the True-Up Rules, as detailed in Appendix A, parties agree that it is appropriate that 2007 and 2008 Customer Care Transition Costs Variance Accounts be created to track certain transition costs related to Customer Care. The transition costs to be tracked in these accounts relate to activities that ABSU and external contractors and internal resources will undertake to transfer knowledge and services to the new service provider. This will include such tasks as training, documentation and management of the vendors through the transition. The transition costs to be tracked in these accounts are subject to a maximum total amount of $11.1 million. The details of the 2007 and 2008 Customer Care Transition Costs Variance Accounts are set out below, as part of the True-Up Rules.

(iv) New CIS

As the Board is aware, the Company is planning to replace its current CIS service with a new CIS that will be owned by the Company. When this system is implemented, which is expected in 2009, its capital cost will be included as part of the Company's utility rate base. Through the Consultative process, and subject to an adjustment described below, the parties have agreed that a reasonable cost for this asset is $118.7 million, including procurement costs of $5.1 million. The parties agree that rates will be set during the period of this agreement on the basis of a CIS cost that will be no higher than $118.7 million. This $118.7 million budget consists of an amount of $42 million for system integrator contract costs, which are subject to a direct competitive tender process, and an amount of about $76.7 million which the Company will manage and control during the CIS procurement and implementation process.

All parties agree that the Company's revenue requirement associated with Customer Care activities for the 2007 to 2012 period will incorporate a portion of the cost for the new CIS of $118.7 million, including procurement costs of $5.1 million, as set out below. The procurement process that provides support for the reasonableness of this cost is described in the evidence of Mario Bauer (Exhibit L-2), and the CIS cost analysis attached thereto. The parties agree that this $118.7 million cost is subject to reduction in the event that the system integrator contract costs arrived at through the CIS procurement process are less than $42 million. In the event that the system integrator costs are $42 million or more, then the parties agree to the cost of $118.7 million for the completion of the Template and the term of this agreement.

While the revenue requirement attributable to CIS shown in Row 3 of the Template is not yet finalized, the parties agree upon the following:

1. As stated above, the parties agree upon the prudence of the CIS procurement process and the capital cost for the new CIS of $118.7 million, which includes procurement costs of $5.1 million.

2. The parties agree that the amounts to be recovered in rates will be reduced, if the system integrator contract costs arrived at through the CIS procurement process are less than $42 million.

3. Subject to the restrictions on CIS costs set forth in this agreement, there is agreement that all prudently incurred and reasonable costs associated with the new CIS, including return and income taxes, should be recoverable in rates, during the term of this agreement, and for the 10-year economic life of the new CIS assets.

4. The parties agree that the term of this agreement will be six years from 2007 to 2012, in order to enable the smoothing and managing of the recovery of the revenue requirement attributable to the new CIS during those years.

5. The parties agree that they support the decision to procure the new CIS as prudent, the inclusion of the new CIS in rate base in 2009, and the recovery of all amounts associated with the new CIS subject to the terms of this agreement. Subject to any adjustment that may be made to rate base as of December 31, 2012 to reflect the actual costs of the new CIS, as set forth below, the parties agree that, as of January 1, 2013, the amount included in opening rate base for the new CIS shall be its 2012 closing net book value of approximately $71.4 million.

6. The parties agree that, for rate-making purposes, the in-service date of the new CIS will be deemed to be July 1, 2009, regardless of the actual in-service date, and the rate base for the new CIS will be calculated in all respects as if it was brought into service on July 1, 2009.

7. The parties agree that, for rate-making purposes, CIS Capital Costs at the end of the term of this Agreement will be treated as follows:

    a. If the actual costs of the New CIS are less than $118.7 million, then the $71.4 million amount included in the January 1, 2013 opening rate base for the New CIS shall be appropriately adjusted downwards;

    b. No capital costs in addition to the amount of $118.7 million will be eligible for closure to rate base on January 1, 2013, unless Enbridge Gas Distribution then demonstrates the reasonableness and prudence of such additional costs; and on the further condition that the only additional amounts eligible for consideration will be confined to increases in the system integrator costs beyond the $42 million provision for those costs included within the budget of $118.7 million.

On this basis, and subject to later adjustment as described at point 2 above, the parties request the Board, as part of the approval of this Settlement Proposal, to approve the prudence and $118.7 million cost of the new CIS, which includes procurement costs of $5.1 million.

The parties agree that there are three, and only three, possible adjustments to be made later to the revenue requirement attributable to CIS for the period 2009 through 2012, as shown in Row 3 of the Template.

The first possible adjustment relates to the tax savings associated with the high Capital Cost Allowance (CCA) for IT hardware and software for the CIS asset. The high CCA produces substantial tax savings in the first two years of the asset's ten year life. The Company acknowledges and agrees that the ratepayers are to receive credit for the full value of these tax savings. The tax rules provide that Enbridge Gas Distribution will be kept whole with respect to income taxes over the full economic life of utility assets, including the 10-year life of the CIS assets. Parties disagree over when the tax savings should be reflected in revenue requirement and rates.

To support a settlement, the parties agree, for ratemaking purposes, to the use of the values included in Row 3 of the Template in determining the revenue requirement for use at True-Up Time. Those values are calculated as if the CIS costs, including tax savings, were calculated on a conventional forward test year cost of service basis for each year during the period 2009-2012. The Company has agreed to use this assumption on the understanding that Enbridge Gas Distribution retains the right to bring an application before the Board seeking a different approach to the timing of when the tax savings are reflected in revenue requirement. Enbridge Gas Distribution agrees that it will, if it elects to make such application, file that application by June 30, 2007. Intervenors' rights to oppose any such application remain unfettered and they retain the right to rely on any and all grounds of opposition considered by them to be appropriate. The parties agree that there will be no inference that Enbridge Gas Distribution has tacitly acquiesced to values in Row 3, by accepting them in this Supplementary Settlement Agreement, and all parties acknowledge that the Company's acceptance of the values in Row 3 is "without prejudice" to the application described above, should the Company decide to file it by June 30, 2007. In the event that the Board approves a different approach to the timing of when the tax savings are reflected in revenue requirement, then parties agree that the values shown in Row 3 of the Template are to be adjusted accordingly. If Enbridge Gas Distribution does not file such an application by June 30, 2007, or if Enbridge Gas Distribution files such an application but the relief requested is not granted, then, subject to the remaining possible adjustments described below, the values in Row 3 of the Template will remain as stated therein.

The two remaining potential adjustments to the CIS revenue requirement amounts for the period 2009 through 2012, as shown in Row 3 of the Template, pertain to Enbridge Gas Distribution's equity ratio and the possibility that the system integrator contract costs resulting from the CIS procurement process are less than $42 million.

The amounts in Row 3 of the Template reflect a 35% level of deemed equity for the Company. The issue of the appropriate level of deemed equity for the Company is currently before the Board in this F2007 rate case, and there may be changes from the 35% level. Parties agree that the amounts in Row 3 of the Template should be adjusted at True-Up Time in the event that the Company's level of deemed equity is changed in the Board's decision in the F2007 rate case.

The amounts in Row 3 of the Template reflect a $118.7 million cost for the new CIS. In the event that the system integrator contract costs arrived at through the CIS RFP process are less than $42 million, then parties agree that the amounts in Row 3 should be adjusted accordingly. In the event that the system integrator costs are $42 million or more, then the parties agree to the cost of $118.7 million for the term of this agreement.

Subject to the outcome of any application which Enbridge Gas Distribution may bring before the Board, as described above, Enbridge Gas Distribution agrees that once the outstanding items on the Template are determined, and completed, and as a result the Normalized 2008 Customer Care Revenue Requirement is established, the Company will not seek any adjustment to its rates or revenue requirement relating to the cost of the new CIS during the term of this agreement. Intervenors similarly agree that they will not seek adjustments to the Company's rates or revenue requirement that are directly or indirectly based on changes in CIS costs.

Notwithstanding the limitations expressed in the preceding paragraphs, the parties agree that in the event that new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period up to and including 2012, and those requirements materially change the level of CIS costs, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the agreement will be established at the IR proceeding. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the IR rules that apply to the Company.

(v) Future revenue-generating opportunities from the new CIS

The Company agrees to use its best efforts to identify and take advantage of opportunities to use the new CIS asset to provide CIS services to third party organizations to generate additional revenue opportunities, and that the gains from any such opportunities shall be shared with ratepayers in a manner to be agreed upon. A consultative group, including Intervenors, may be convened to consider how such opportunities would be addressed. The parties agree that, in the event that the sharing of such gains cannot be agreed upon by the parties, then they will put the issue of the appropriate gainsharing to be used to the Board. The parties agree that any gains to be shared with ratepayers would be cleared to ratepayers by way of an annual adjustment to delivery rates.

Billing services on the Enbridge Gas Distribution bill are covered by the Supplementary Settlement Proposal related to open bill access (Ex. N1-1-1, Appendix C), and are not included in or affected by the provisions set out above.

APPENDIX A – TRUE-UP RULES

Attached to this Appendix A is a document entitled "Customer Care and CIS Settlement Template" (the "Template"). The parties have completed each of the boxes A1 through G17 of the Template, by inserting a dollar amount, or zero, or a TBD (To Be Determined) which will be completed at the True-Up Time. The following rules apply to the completion of the Template:

1) Where in the Template there is a dollar figure or zero already inserted in any box, that figure is agreed by the parties, and subject to paragraphs 3, 4 and 6 below, will not be altered.

2) The figures agreed to by the parties which are fixed and not subject to change, and which are already included in certain boxes within the Template, include the following:

    a. Rows 1, 2 and 2a: rows 1 and 2 represent the amounts that parties agree can be recovered in rates related to payments by Enbridge Gas Distribution to ABSU to provide CIS services and the payments by ABSU to ECSI for the use of the existing CIS asset, until the new CIS asset is in service. Row 2a represents the amounts to be paid to CWLP for the use of the CIS asset from January 1, 2007 to March 31, 2007. Parties agree that a total of $28.9 million shall be included on these rows, divided into the individual amounts included in the Template.

    b. Row 4: parties agree to the figures included in the Template as the amounts to be paid for the hosting and support of the new CIS. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

    c. Row 5: parties agree to the figures included in the Template as the amounts to be recovered for the Company's backoffice costs (excluding bad debt) associated with both the old and the new CIS. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

    d. Rows 6 and 7: SAP has been chosen as the provider for the software that will support the new CIS. This software may require some modifications or adaptations, from time to time, to fully support the CIS. The parties agree to the figures included rows 6 and 7 of the Template as the amounts to be paid to SAP for licence fees and for modifications that may be necessary. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

e. Row 8: box 8A includes the amount of $16.9 million, which is the amount that parties have agreed can be recovered in rates related to the provision of Customer Care services by CWLP for the period from January 1, 2007 to March 31, 2007 (which is the date on which ABSU will begin providing Customer Care services on a temporary or permanent basis). Given that CWLP will stop providing services to Enbridge Gas Distribution as of April 2007, the amounts to be reflected in boxes 8B, 8C, 8D, 8E and 8F are zero.

f. Row 11: parties agree to the figures included in the Template as the amounts to be recovered for Customer Care licences to support the existing and new Customer Care service provider delivery of Collections, E-Billing and text to speech voice capability functions. These amounts are based on Enbridge Gas Distribution estimates which Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

g. Row 12: parties agree to the figures included in the Template as the amounts to be recovered for the Company's backoffice costs (excluding bad debt) associated with Customer Care services. These amounts are based on Enbridge Gas Distribution estimates which Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

h. Row 13: this row includes the costs incurred by the Company, and accepted for recovery from ratepayers, related to the procurement of a new customer care service provider. The parties have agreed that a total amount of $4.9 million may be recovered at row 13. This total amount represents the internal and external procurement costs for the new Customer Care services that have been determined by the parties to be prudently incurred and reasonable for recovery from ratepayers. This total amount is allocated equally over the five years from 2008 to 2012. Thus, the amount of $0.98 million is inserted in each of the boxes A13 to F13.

i. Row 17: the total number of customers for each year.

3) Row 3 includes the revenue requirement associated with the new CIS for each of the years from 2007 to 2012, to be filled in as follows:

a. The amounts in boxes A3 and B3 shall be zero, since there is no revenue requirement associated with the new CIS until 2009.

b. The amounts in boxes C3, D3, E3 and F3 represent the annual revenue requirement associated with each of 2009, 2010, 2011 and 2012 for the new CIS. These amounts, which total $46.210 million, are based upon the agreed-upon cost of the new CIS of $118.7 million. The derivation of these amounts is set out in the spreadsheets attached as Appendix B and the total of $46.210 million is the sum of the items in Columns 1, 2, 3 and 4 at line 12 on the first page of Appendix B. These amounts are subject to adjustment as follows:

   i. the amounts in row 3 of the Template reflect a $118.7 million cost for the new CIS. In the event that the system integrator contract costs arrived at through the CIS RFP process are less than $42 and the overall cost is therefore reduced, then parties agree that the amounts in row 3 should be changed to correspond to the lower new CIS cost;

   ii. the amounts in row 3 of the Template reflect a 35% level of deemed equity for the Company. The issue of the appropriate level of deemed equity for the Company is currently before the Board in this F2007 rate case, and there may be changes from the 35% level. Parties agree that the amounts in row 3 of the Template should be changed in the event that the Company's level of deemed equity is changed;

   iii. In the event that the Company is successful in an application to the Board for a different approach to the timing of when tax savings associated with the new CIS are reflected in revenue requirement, then corresponding changes will be made to the amounts in row 3.

4) The amounts to be inserted in boxes A9 and B9 shall be determined by the parties as the prudent and reasonable amounts for recovery from ratepayers for sums paid or forecast to be payable by the Company to ABSU for Customer Care services during the period April 1, 2007 through September 30, 2008, in accordance with the following criteria:

   a. In the event that ABSU is chosen as the new service provider for Customer Care services from and after April 1, 2007 until December 31, 2012, then the figures to be inserted in boxes A9 and B9 are zero, because there will be no need for a transition period to a new service provider;

b. In the event that a third party other than ABSU is chosen as the new service provider for Customer Care services, then there will be the need for a transition period, for a maximum of 18 months from April 1, 2007, during which ABSU will provide Customer Care services until the new service provider can be fully phased-in.

c. The Company has reached agreement with ABSU for Customer Care services to be provided, on a transition basis for 2007 and 2008 in the event that ABSU is not the successful Customer Care bidder. For settlement purposes, subject to subparagraph (d) below, the Parties agree that amounts of up to $52,263,000 for 2007 and $42,623,000 for 2008 will be included in boxes A9 and B9. These numbers represent the maximum agreed-upon level of costs that the Company may recover in rates in respect of the amounts charged by ABSU during 2007 and 2008 for Customer Care services, on a transitional basis, based on a recoverable cost of $38 per customer per year and a transition period of 18 months;

d. The Company will make best efforts to reduce the length of the transition period from 18 months, and to reduce the actual forecast costs per customer from ABSU to be less than currently forecast. In the event that the actual costs to date and updated forecast costs from ABSU at True-up Time for Customer Care services for the transition period are less than $52,263,000 for 2007 or $42,623,000 for 2008, then the numbers to be inserted in boxes A9 and B9 will be the actual costs to date and updated forecast costs at True-Up Time.

e. The amounts to be inserted in boxes C9, D9, E9 and F9 are zero because, in any event, the transition period for customer care services will not extend beyond 2008.

5) The amounts to be inserted in boxes A10 to F10 are the reasonable forecast annual costs of the new Customer Care service provider, to be determined at the True-Up Time through the results of the Customer Care procurement process. In the event that ABSU is chosen as the new service provider, it is expected that these amounts will be effective as of April 1, 2007. In the event that a third party other than ABSU is chosen as the new service provider, it is expected that these amounts will begin at some time in 2007 or 2008, because of the need for transition time and activities. The amounts to be included in these boxes are subject to review by the Consultative for prudence and reasonableness. In the event that the Intervenors and the Company do not agree, the issue of prudence and reasonableness will be determined by the Board.

6) The amounts at rows 14 and 15 represent the transition costs associated with moving from CWLP as the Customer Care service provider to a different third party service provider. The transition costs to be included in these rows, and tracked in the 2007 and 2008 Customer Care Transition Costs Variance Accounts, relate to activities that ABSU and external contractors and internal resources will undertake to transfer knowledge and services to the new service provider. This will include such tasks as training, documentation and management of the vendors through the transition.

    a. In any event, the number in boxes A14/A15 will be zero.

    b. In the event that ABSU is chosen as the new Customer Care service provider then the amounts to be inserted in boxes B14 to F14 and B15 to F15 are zero and subparagraphs 6(c) to (f) do not apply.

    c. In the event that a different third party is chosen as the new Customer Care service provider, then a total amount of $11.1 million will be included on rows 14 and 15. This total amount will be split equally between the years 2008 to 2012, in the amount of $2.22 million per year. Thus, each of boxes B14/B15, C14/C15, D14/D15, E14/E15 and F14/F15 will include the number $2.22 million.

    d. The Company will record all prudent and reasonable amounts spent for services, both internal and external, to facilitate the transition from CWLP/ABSU providing Customer Care services to a new service provider in the 2007 and 2008 Customer Care Transition Costs Variance Accounts, to a total maximum of $11.1 million. It is agreed that amounts paid for internal costs shall not include the costs of employees or other resources already included in the budget for the year and re-assigned to this transition, unless a specific new resource was acquired to backfill those other functions.

    e. Commencing in 2008, and continuing each year until 2012, the Company will expense the amount of $2.22 million for Customer Care costs, and will at the same time, deduct the same amount from the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts. The parties agree that, even if the outstanding balance in the 2007 and 2008 Customer Care Transition Costs Variance Accounts becomes zero before 2012, the Company is still entitled to expense and recover the amount of $2.22 million for each year until 2012. The parties further agree that no negative balances will be reflected in the 2007 and 2008 Customer Care Transition Costs Variance Accounts.

f. Parties agree that if the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts are less than $11.1 million as of December 31, 2008, then the difference between $11.1 million and the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts will be credited to ratepayers with interest in equal amounts in 2009 to 2012.

7) Row 16 will be the totals of each of the columns, to be completed when all of the above figures are determined.

8) Column G will be the totals of each of the rows, to be completed when all of the above figures are determined.

9) Box G16 will be the total of all Customer Care costs and revenue requirement forecast for the period (the “Total Customer Care Forecast”).

10) Box G17, already completed, is the forecast total of annual numbers of customers during the period (the “Customer Count”).

At True-Up Time, once the Template has been completed, then the Normalized 2007 Customer Care Revenue Requirement can be determined. This will be calculated by starting with the Total Customer Care Revenue Requirement for 2007 to 2012, which is the sum of boxes A16 to F16. That Total Customer Care Revenue Requirement will then be placed into an amortization model that calculates, using the IR annual adjustment that is approved for Enbridge Gas Distribution, the Normalized 2007 Customer Care Revenue Requirement which is the number that, when adjusted for IR annual adjustment for each year from 2008 through 2012, would allow the Company to fully recover the Adjusted Customer Care Revenue Requirement for 2007 to 2012.

At the same time, parties will calculate the 2007 Customer Care Revenue Requirement Variance by taking the difference between the Normalized 2007 Customer Care Revenue Requirement and the placeholder of $90.8 million. The Company will credit or debit the 2007 Customer Care Revenue Requirement Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012.

Attached to this Appendix A is an illustrative example of how the True-Up will be applied. For the purpose of this example, the following assumptions have been employed: (i) at row 3, the CIS cost is recovered by recognizing the tax shield benefit in the first four years, and a deemed equity level of 35% is assumed; (ii) ABSU is not awarded the Customer Care contract, so there are transition costs included at row 9; (iii) at row 10, the new CIS service provider contract cost is $60 million per year; and (iv) the

IR Annual Adjustment is 1%. The illustrative example sets out the steps that are followed, and the amortization model that is used, to derive the 2007 Customer Care Revenue Requirement Variance and the Normalized Customer Care Revenue Requirements for 2007 to 2012.

Customer Care and CIS Settlement Template

#	Category of Cost	A 2007	B 2008	C 2009	D 2010	E 2011	F 2012	G Totals
	CIS Related Categories							
1	Old CIS Licence Fee							
2	Old CIS Hosting and Support	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000
2a	Incumbent (CWLP) CIS Services being provided from January to March 2007							
3	New CIS Capital Cost	$0	$0	$880,000	($5,340,000)	$25,810,000	$24,860,000	$46,210,000
4	New CIS Hosting and Support	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000
5	CIS Backoffice (EGD Staffing)	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254
6	SAP Licence Fees	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500
7	SAP Modifications	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000
	Customer Care Related Categories							
8	Incumbent (CWLP) Customer Care Services being provided from - January to March 2007	$16,900,000	$0	$0	$0	$0	$0	$16,900,000
9	Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sep 30, 2008	Up to $52,263,000	Up to $42,623,000	$0	$0	$0	$0	$0
10	New Service Provider Contract Cost	TBD	TBD	TBD	TBD	TBD	TBD	$0
11	Customer Care Licences	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000
12	Customer Care Backoffice (EGD staffing)	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071
13	Customer Care Procurement Costs	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000
14	Transition Costs - Consultants and ISP	$0	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$11,100,000
15	Transition Costs - EGD Staffing							
16	**Total CIS & Customer Care**	TBD	TBD	TBD	TBD	TBD	TBD	TBD
17	Number of Customers	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613

Customer Care and CIS Settlement Template - Example for purpose of illustrating True-Up

#	Category of Cost	A 2007	B 2008	C 2009	D 2010	E 2011	F 2012	G Totals
	CIS Related Categories							
1	Old CIS Licence Fee							
2	Old CIS Hosting and Support	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000
2a	Incumbent (CWLP) CIS Services being provided from January to March 2007							
3	New CIS Capital Cost (Intervenor Model @ 35% Equity)	$0	$0	$880,000	($5,340,000)	$25,810,000	$24,860,000	$46,210,000
4	New CIS Hosting and Support	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000
5	CIS Backoffice (EGD Staffing)	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254
6	SAP Licence Fees	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500
7	SAP Modifications	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000
	Customer Care Related Categories							
8	Incumbent (CWLP) Customer Care Services being provided from - January to March 2007	$16,900,000	$0	$0	$0	$0	$0	$16,900,000
9	Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sep 30, 2008	$52,263,530	$42,623,220	$0	$0	$0	$0	$94,886,750
10	New Service Provider Contract Cost - (Values placed for illustrative purposes)	$0	$24,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$264,000,000
11	Customer Care Licences	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000
12	Customer Care Backoffice (EGD staffing)	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071
13	Customer Care Procurement Costs	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000
14	Transition Costs - Consultants and ISP	$0	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$11,100,000
15	Transition Costs - EGD Staffing							
16	**Total CIS & Customer Care**	$88,863,530	$85,246,220	$82,132,290	$76,634,454	$106,947,877	$106,166,204	$545,990,575
17	Number of Customers	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613

#	True-Up Process Step	A	B	C	D	E	F	G
18	The Normalized 2007 Customer Care Revenue Requirement can be determined. This will be calculated by starting with the Total Customer Care Revenue Requirement for 2007 to 2012, which is the amount in box G16	$545,990,575						
19	That Total Customer Care Revenue Requirement will then be placed into an amortization model that calculates, using the IR annual adjustment that is approved for Enbridge Gas Distribution, the Normalized 2007 Customer Care Revenue Requirement which is the number that, when adjusted for IR annual adjustment for each year from 2008 through 2012, will allow the Company to fully recover the Total Customer Care Revenue Requirement for 2007 to 2012	$88,749,876.15						
20	The Normalized 2007 Customer Care Revenue Requirement will then be compared to the 2007 placeholder of $90.8 million, and the difference will be the 2007 Customer Care Revenue Requirement Variance.	($2,050,124)						
21	The Company will credit or debit the 2007 Customer Care Revenue Requirement Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012.		($410,025)	($410,025)	($410,025)	($410,025)	($410,025)	
22	The Normalized 2008 Customer Care Revenue Requirement will be the Normalized 2007 Customer Care Revenue Requirement, plus or minus the IR annual adjustment that is approved for Enbridge Gas Distribution.		$89,637,375	$90,533,749	$91,439,086	$92,353,477	$93,277,012	
23	**Total Customer Care Revenue By Year (Including repayment of 2007 variance)**	$ 90,800,000	$ 89,227,350	$ 90,123,724	$ 91,029,061	$ 91,943,452	$ 92,866,987	$ 545,990,575
24	Normalized Customer Care Revenue Requirement Per Customer without Bad Debt	$ 49.58	$ 47.51	$ 46.80	$ 46.12	$ 45.48	$ 44.87	
25	IR Annual Adjustment	1%						

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Capital Structure
65% Incremental Long Term Debt / 35% Equity

Line No.		Col. 1 Component	Col. 2 Indicated Cost Rate	Col. 3 Return Component	Col. 4 (4 dec.) Return Component
		%	%	%	%
1.	Long-term debt	65.00	5.35	3.48	3.4775
2.	Short-term debt	0.00	0.00	0.00	0.0000
3.		65.00		3.48	3.4775
4.	Preference shares	0.00	0.00	0.00	0.0000
5.	Common equity	35.00	8.39	2.94	2.9365
6.		100.00		6.42	6.4140

	($Millions)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
7.	Ontario Utility Income ($M)	6.69	9.89	(10.77)	(10.92)	(11.07)	(11.22)	(11.37)	(11.52)	(11.67)	(11.81)
8.	Rate base ($M)	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
9.	Indicated rate of return %	5.921 %	9.783 %	(12.074)%	(14.125)%	(16.921)%	(20.963)%	(27.311)%	(38.734)%	(65.372)%	(198.101)%
10.	(Deficiency) in rate of return %	(0.493)%	3.369 %	(18.488)%	(20.539)%	(23.335)%	(27.377)%	(33.725)%	(45.148)%	(71.786)%	(204.515)%
11.	Net (deficiency) ($M)	(0.56)	3.41	(16.49)	(15.88)	(15.27)	(14.65)	(14.04)	(13.43)	(12.81)	(12.19)
12.	Gross (deficiency) ($M)	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.05)	(19.08)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Rate Base

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Property, plant, and equipment										
1.	Cost or redetermined value	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93
2.	Accumulated depreciation	(5.95)	(17.84)	(29.73)	(41.62)	(53.51)	(65.41)	(77.30)	(89.19)	(101.08)	(112.97)
3.	Net Property, plant, and equipment	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
	Allowance for working capital										
4.	Accounts receivable merchandise finance plan	-	-	-	-	-	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-	-	-	-	-	-
12.		-	-	-	-	-	-	-	-	-	-
13.	Ontario utility rate base	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Income

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Revenue										
1.	Gas sales	-	-	-	-	-	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-	-	-	-	-	-
4.	Storage service	-	-	-	-	-	-	-	-	-	-
5.	Other operating revenue	-	-	-	-	-	-	-	-	-	-
6.	Interest and property rental	-	-	-	-	-	-	-	-	-	-
7.	Other income	-	-	-	-	-	-	-	-	-	-
8.	Total revenue	-	-	-	-	-	-	-	-	-	-
	Costs and expenses										
9.	CIS -selection procurement cost	5.10	-	-	-	-	-	-	-	-	-
10.	Operation and maintenance	-	-	-	-	-	-	-	-	-	-
11.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
12.	Provincial capital taxes	0.16	-	-	-	-	-	-	-	-	-
13.	Total costs and expenses	17.15	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
14.	**Utility income before inc. taxes**	(17.15)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)
	Income taxes										
15.	Excluding interest shield	(22.42)	(20.51)	-	-	-	-	-	-	-	-
16.	Tax shield on interest expense	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
17.	Total income taxes	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
18.	**Ontario utility net income**	6.69	9.89	(10.77)	(10.92)	(11.07)	(11.22)	(11.37)	(11.52)	(11.67)	(11.81)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Taxable Income and Income Tax Expense

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1.	Utility income before income taxes	(17.15)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)
	Add Backs										
2.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
3.	Large corporation tax	-	-	-	-	-	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-	-	-	-	-	-
6.	Total added back	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
7.	Sub total - pre-tax income plus add backs	(5.26)	-	-	-	-	-	-	-	-	-
	Deductions										
8.	Capital cost allowance - Federal	56.80	56.80	-	-	-	-	-	-	-	-
9.	Capital cost allowance - Provincial	56.80	56.80	-	-	-	-	-	-	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-	-	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-	-	-	-	-	-
16.	Total Deductions - Federal	56.80	56.80	-	-	-	-	-	-	-	-
17.	Total Deductions - Provincial	56.80	56.80	-	-	-	-	-	-	-	-
18.	Taxable income - Federal	(62.06)	(56.80)	-	-	-	-	-	-	-	-
19.	Taxable income - Provincial	(62.06)	(56.80)	-	-	-	-	-	-	-	-
20.	Income tax provision - Federal @ 22.12 %	(13.73)	(12.56)	-	-	-	-	-	-	-	-
21.	Income tax provision - Provincial @ 14.00 %	(8.69)	(7.95)	-	-	-	-	-	-	-	-
22.	Income tax provision - combined	(22.42)	(20.51)	-	-	-	-	-	-	-	-
23.	Part V1.1 tax	-	-	-	-	-	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(22.42)	(20.51)	-	-	-	-	-	-	-	-
	Tax shield on interest expense										
26.	Rate base as adjusted	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
27.	Return component of debt	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%
28.	Interest expense	3.93	3.52	3.10	2.69	2.28	1.86	1.45	1.03	0.62	0.21
29.	Combined tax rate	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612
30.	Income tax credit	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
31.	**Total income taxes**	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Revenue Requirement

Line No.	($Millions)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Cost of capital										
1.	Rate base	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
2.	Required rate of return	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%
3.	Cost of capital	7.25	6.48	5.72	4.96	4.20	3.43	2.67	1.91	1.15	0.38
	Cost of service										
4.	CIS -selection procurement cost	5.10	-	-	-	-	-	-	-	-	-
5.	Operation and maintenance	-	-	-	-	-	-	-	-	-	-
6.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
7.	Municipal and other taxes	0.16	-	-	-	-	-	-	-	-	-
8.	Cost of service	17.15	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
	Misc. & Non-Op. Rev										
9.	Other operating revenue	-	-	-	-	-	-	-	-	-	-
10.	Other income	-	-	-	-	-	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-	-	-	-	-	-
	Income taxes on earnings										
12.	Excluding tax shield	(22.42)	(20.51)	-	-	-	-	-	-	-	-
13.	Tax shield provided by interest expens	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
14.	Income taxes on earnings	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
	Taxes on deficiency										
15.	Gross deficiency	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.05)	(19.08)
16.	Net deficiency	(0.56)	3.41	(16.49)	(15.88)	(15.27)	(14.65)	(14.04)	(13.43)	(12.81)	(12.19)
17.	Taxes on deficiency	0.32	(1.93)	9.32	8.98	8.63	8.28	7.94	7.59	7.24	6.89
18.	**Revenue requirement**	0.88	(5.34)	25.81	24.86	23.90	22.93	21.98	21.02	20.06	19.08
	Revenue at existing Rates										
19.	Gas sales	-	-	-	-	-	-	-	-	-	-
20.	Transportation service	-	-	-	-	-	-	-	-	-	-
21.	Transmission, compression and storag	-	-	-	-	-	-	-	-	-	-
22.	Rounding adjustment	-	-	-	-	-	-	-	-	-	-
23.	Revenue at existing rates	-	-	-	-	-	-	-	-	-	-
24.	**Gross revenue deficiency**	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.06)	(19.08)

APPENDIX C

ENBRIDGE GAS DISTRIBUTION INC.

2007 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0034

INTERIM ORDER DATED MARCH 26, 2007

JULY 5, 2007

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0034

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2007.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Paul Vlahos
Member

Ken Quesnelle
Member

INTERIM RATE ORDER ARISING FROM 2007 TEST YEAR SETTLEMENT PROPOSAL (EB-2006-0034)

Enbridge Gas Distribution Inc. ("EGDI") filed an application dated August 25, 2006 with the Ontario Energy Board (the "Board") under the Section 36 of the *Ontario Energy Board Act*, requesting a rate increase effective January 1, 2007. The Board issued a Notice of Application dated September 7, 2006 and subsequently has issued seven procedural orders. The procedural orders provided for, among other things, the convening of a Settlement Conference and direction for the filing and hearing of any Settlement Proposal.

The Settlement Conference commenced on December 11, 2006 and a Settlement Proposal was filed with the Board on January 24, 2007. Parties to the Settlement indicated that there were ongoing consultations on certain unsettled issues and additional settled issues could be filed during the course of the proceeding. If additional issues were partly or completely settled, the parties would file a supplementary settlement agreement that would explain the settlements, and the financial incremental impacts of such settlements. The Board heard and, with clarifications made on the record, accepted the Settlement Proposal on January 29, 2006.

The Settlement indicated that the implementation of the settlement package of issues, comprised of issues 1.1 to 1.8, 2.1, 2.2, 3.2, 3.5, 3.7 to 3.9, 3.11 to 3.15 and 9.1, will result in a revenue deficiency of $29.9 million. The Settlement Proposal included the agreement by all parties that …

> … for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. GEC's and Pollution Probe's agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1. (Ex.N1 Tab1 Schedule 1 p9 /filed January 24, 2007)

On February 23, 2007 EGDI filed a draft interim rate order, including supporting documentation, for the Board's approval. EGDI indicated that the draft order reflected the impacts of the 2007 Settlement Proposal dated January 24, 2007. EGDI proposed that intervenors wishing to comment on the draft should file their submissions by March 2, 2007. EGDI also indicated that it would file a draft rate order under docket number EB-2007-0049 on March 2, 2007 seeking approval of rates effective April 1, 2007 using the Board approved QRAM methodology. The rates approved in EB-2007-0049 would immediately supersede those included, as appendix A, in this rate order.

The draft interim order included the following elements:

- Interim rates designed to recover a 2007 Test Year Revenue Requirement of $3,098.557 million.

- Revenue Adjustment Rate Rider applicable to billed volumes during the period April 1, 2007 to December 31, 2007 to recover $5.074 million in revenue. $5.074 million is the amount EGDI would have recovered if the proposed interim rates had been implemented on January 1, 2007.

On March 2, 2007 TransCanada Energy Ltd. submitted a request for explanation and reasons regarding the increase in Rate 125. EGDI provided a response on March 9, 2007.

Under proceeding EB-2007-0049, the April 2007 QRAM application, the Industrial Gas Users Association ("IGUA") submitted their concerns about the rates proposed in that proceeding and indicated their objections in the event that they did not receive a satisfactory explanation for the increase in certain rates. TransAlta Cogeneration L.P. and TransAlta Energy Corp also filed a submission indicating their support of IGUA's position. The QRAM panel referred this and subsequent IGUA and EGDI correspondence to this proceeding for consideration. During Day 15 of the EB-2006-0034 oral proceeding, IGUA indicated that it no longer objected to the proposed rates.

Upon reviewing the filed materials, the Board finds it appropriate to proceed with an interim rate order, effective January 1, 2007 with implementation beginning April 1, 2007.

A final rate order will be issued by the Board subsequent to the issuance of the Board's 2007 Test Year Decision with Reasons.

The Board notes that the rates in this Order will be immediately superceded by the rates approved in the April 2007 QRAM Decision and Order (EB-2007-0049)

THE BOARD ORDERS THAT:

1. The 2007 Settlement Proposal, dated January 24, 2007, attached as Appendix "A" and Supporting Documentation, attached as Appendix "B" to this order, are accepted as the basis for the rates in this order.

2. Rate Rider E, attached as Appendix “C”, will apply as a rate adjustment to a consumer’s actual consumption for the period April 1, 2007 to December 31, 2007.

3. The rates in the Rate Handbook, attached as Appendix “D” to this interim order, are hereby approved effective January 1, 2007. These rates will be immediately superceded by the rates resulting from the April 2007 QRAM decision.

DATED at Toronto, March 26, 2007

ONTARIO ENERGY BOARD

Original signed by

Peter H. O’Dell
Assistant Board Secretary

APPENDIX "A"

TO INTERIM RATE ORDER

BOARD FILE NO. EB-2006-0034

DATED MARCH 26, 2007

SETTLEMENT PROPOSAL

JANUARY 24, 2007

TABLE OF CONTENTS

ISSUE **DESCRIPTION (& EVIDENTIARY REFERENCE)**

PREAMBLE

OVERVIEW

1 RATE BASE (Exhibit B)

1.1 Are the amounts proposed for the 2007 Rate Base appropriate

1.2 Are the amounts proposed for Capital Expenditures in 2007 appropriate (B1-2-1)

1.3 Is the budget amount proposed in 2007 for Safety and Integrity projects appropriate (B1-3-1)

1.4 How should the Board deal with the Leave to Construct ("LTC") projects included in the 2007 capital budget given that there will be separate Board proceedings for the LTC projects (B1-T3-S1)

1.5 Has the Company met the requirements of the Board's directive from the 2006 rate case to file an independent cost benchmark study for the EnVision project? (B1-6-1)

1.6 What are the appropriate EnVision cost and benefits and how should they be reflected in 2007 rates?

1.7 Is the business case, including the total project amount of $133 million, proposed for the Automatic Meter Reading project ("AMR") justified? (B1-7-1)

1.8 Is the proposed recovery of AMR costs in 2007 rates appropriate?

2 OPERATING REVENUE (Exhibit C)

2.1 Is the proposed amount for 2007 Transactional Services revenue appropriate, and is the associated sharing mechanism in accordance with the 2006 decision? (C1-4-1)

2.2 Is the proposed total 2007 Other Revenue Forecast appropriate? (C1-5-1)

ISSUE	**DESCRIPTION (& EVIDENTIARY REFERENCE)**
2.3	Is the forecast of degree days appropriate? (C2-4-1)
2.4	Are the average use-per-customer forecasts for rate class 1 and rate class 6 appropriate? (C1-3-1 and C2-3-1)
2.5	Is the proposed 2007 contract gas volume and revenue forecast appropriate? (C1-3-1)
2.6	Is the proposed 2007 General Service gas volume and revenue forecast appropriate? (C1-3-1)
3	**OPERATING COST (Exhibit D)**
3.1	Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate? (D1-4-1, D1-4-2)
3.2	Is the overall level of the 2007 Operation and Maintenance Budget appropriate? (D1-2-1)
3.3	Is the Company's proposed fuel switching program appropriate?
3.4	Is the Company's proposed Energy Link Program appropriate?
3.5	Is the budget for Human Resources related costs appropriate? (D1-4-1)
3.6	Do the revisions to the Regulatory Cost Allocation Methodology (RCAM) meet the Board's directives in the 2006 decision?
3.7	Is the proposed level of corporate cost allocation for 2007 appropriate?
3.8	Is Company's forecast level of Regulatory and OEB related costs for 2007 appropriate?
3.9	Is Enbridge's decision to change to a December 31 taxation year-end , in 2007, appropriate? (D1-5-1)
3.10	Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives? (D1-4-3)
3.11	Is the proposal to change depreciation rates for 2007, as proposed in the depreciation study, and the impact on 2007 customer rates,

ISSUE DESCRIPTION (& EVIDENTIARY REFERENCE)

appropriate? (D1-13-1, D2-2-1)

3.12 Is the proposal for the establishment of 2007 Deferral and Variance Accounts appropriate? (D1-7-1)

3.13 Is the proposal for the disposition of existing Deferral and Variance Accounts appropriate? (D1-7-2)

3.14 Are the amounts proposed to be included in rates for capital and property taxes appropriate?

3.15 Is the amount proposed to be included in rates for income taxes, including the methodology, appropriate?

4 COST OF CAPITAL (Exhibit E)

4.1 What is the Return on Equity (ROE) for EGDI for the 2007 test year as calculated pursuant to the ROE Guidelines?

4.2 Are Enbridge's proposed costs for its debt and preference share components of its capital structure appropriate? (E1-2-1)

4.3 Is the proposal to change the equity component of the deemed capital structure from 35% to 38% appropriate? (E2-2-1)

5 COST ALLOCATION (Exhibit G)

5.1 Is the Applicant's cost allocation appropriate and is it based in its 2006 Board approved methodology? (G2-T1-S1)

5.2 Is the proposal to recover Demand Side Management costs in delivery charges, as opposed to load balancing charges, appropriate? (from G2-3-1 to G2-3-4)

6 RATE DESIGN (Exhibit H)

6.1 Is the proposal to introduce delivery demand charges for Rates 100 and 145 reasonable? (H1-1-1)

6.2 Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable? (H1-1-1)

ISSUE DESCRIPTION (& EVIDENTIARY REFERENCE)

6.3 Should the Board approve the contents of the Applicant's Rate Handbook? (H1-1-1, H2-6-1; A1-14-2)

6.4 Is the proposed treatment of bundled transportation charges and T-service credit appropriate in light of the Board's Decision in RP-2003-0203 and the settlement agreement? (H1-1-1)

7 CUSTOMER CARE SUPPORT, CUSTOMER CARE SYSTEM, AND OPEN BILL ACCESS

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision? (D1-12-3)

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account? (D1-10-1, p. 2/AppA)

7.3 Are the forecast costs of the new CIS system appropriate? (B1-5-1, p. 3)

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs? (D1-12-1, p. 2 and D3-2-1, p. 1)

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP 2005-0001? (D1-11-1 to 5)

8 OTHER ISSUES

8.1 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the NGEIR (EB-2005-0551) proceeding will be appropriately captured and reflected in this proceeding?

8.2 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the DSM

ISSUE	DESCRIPTION (& EVIDENTIARY REFERENCE)
	(EB-2006-0021) proceeding will be appropriately captured and reflected in this proceeding?
9	**RATE IMPLEMENTATION**
9.1	How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?
9.2	Should the Board set interim rates, effective January 1, 2007, to allow Enbridge to begin to recover its prospective revenue deficiency?

ATTACHMENTS

Appendix A- Deferral and Variance Accounts Balances

Appendix B- Approximations of rate impacts of the Settlement Proposal

PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board ("OEB" or "Board") in connection with the application of Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company"), for an order or orders approving or fixing rates for the sale, distribution, transmission, and storage of gas for its 2007 fiscal year (the "Test Year").[1] A Settlement Conference was held between December 11, 2006 and January 5, 2007 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* ("Settlement Guidelines"). Ken Rosenberg acted as facilitator for the Settlement Conference. Settlement discussions between parties continued after that time. This Settlement Proposal arises from the Settlement Conference and subsequent discussions.

Enbridge Gas Distribution and the following intervenors (collectively, the "parties"), as well as Ontario Energy Board technical staff ("Board Staff"), participated in the Settlement Conference:

CONSUMERS COUNCIL OF CANADA (CCC)
DIRECT ENERGY MARKETING LIMITED (Direct Energy)
ENERGY PROBE RESEARCH FOUNDATION (Energy Probe)
GREEN ENERGY COALITION (GEC)
HVAC COALITION INC. (HVAC)
INDUSTRIAL GAS USERS ASSOCIATION (IGUA)
ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS (OAPPA)
ONTARIO ENERGY SAVINGS L.P. (OESLP)
POLLUTION PROBE
SCHOOL ENERGY COALITION (Schools)
SUPERIOR ENERGY MANAGEMENT (a division of Superior Plus Inc.) (Superior)
TRANSALTA COGENERATION L.P. AND TRANSALTA ENERGY CORP. (TransAlta)
TRANSCANADA PIPELINES LIMITED (TransCanada)
UNION ENERGY LIMITED PARTNERSHIP (Union Energy)
UNION GAS LIMITED (Union)
VULNERABLE ENERGY CONSUMERS COALITION (VECC)

The Settlement Proposal deals with all of the issues listed at Appendix "A" to the Board's Procedural Order #2, dated October 20, 2006 (the "Issues List"). The numbers ascribed to each of the issues correlate to the section numbers in the Settlement Proposal and each issue falls within one of the following three categories:

1. ***complete settlement*** **–** if the Settlement Proposal is accepted by the Board, the issue will not be addressed at the hearing because Enbridge

[1] In this Settlement Proposal, the terms "2007 fiscal year", "fiscal 2007" and "Test Year" each refer to the twelve-month period commencing January 1, 2007 and ending December 31, 2007.

Gas Distribution and all other parties who take any position on the issue agree to the proposed settlement;

2. ***incomplete settlement* –** if the Settlement Proposal is accepted by the Board, portions of the issue will be addressed at the hearing because parties are only able to agree on some, but not all, aspects of the issue; and,

3. ***no settlement* –** the issue will be addressed at the hearing because the parties who participated in the negotiation of the issue are unable to reach a settlement on the issue.

More particularly, the Settlement Proposal depicts the 47 issues enumerated on the Issues List as follows:

Complete Settlement Parties will not address the issue at the hearing	**Incomplete Settlement** Parties will address one or more parts of the issue at the hearing	**No Settlement** Parties will address the issue at the hearing
25 issues completely settled Issues 1.1, 1.3 to 1.8, 2.1, 2.2, 3.1, 3.5, 3.7 to 3.9, 3.11, 3.14, 3.15, 4.1, 5.1, 5.2, 6.1, 6.4, 8.1, 8.2 and 9.2	7 issues partly settled Issues 1.2, 3.2, 3.12, 3.13, 6.2, 6.3 and 9.1	15 issues not settled Issues 2.3 to 2.6, 3.3, 3.4, 3.6, 3.10, 4.2, 4.3 and 7.1 to 7.5

Issue 3.2, which relates to the Company's O&M Budget for the Test Year is an incomplete settlement, however, it should be noted that GEC and Pollution Probe object to the settled portions of this issue. Issue 9.1, which relates to rate implementation, is an incomplete settlement, however, it should be noted that Schools objects to the settled portions of this issue.

The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise. Any parties that are identified as not having participated in the negotiations of the issue also take no position on any settlement or other wording pertaining to the issue. Board Staff participated in the Settlement Conference, and has advised the parties that it does not oppose the proposed settlement on any of the completely settled or partly settled issues. However, in accordance with the Rules and the Settlement Guidelines, Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Proposal.

The Settlement Proposal describes the agreements reached on the completely settled and partially settled issues. The Settlement Proposal identifies the parties who agree and who disagree with each settlement, or alternatively who take no position on the issue. Finally, the Settlement Proposal provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties who agree with the individual settlements are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the settled issues. In the event that the Board does not accept the proposed settlement of any issue, further evidence may be required on the issue for the Board to consider it fully.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit A1, Tab 8, Schedule 1 is referred to as A1-8-1. A concise description of the content of each exhibit is also provided. In this regard, Enbridge Gas Distribution's response to an interrogatory is described by citing the name of the party and the number of the interrogatory (e.g., Board Staff Interrogatory #1). The identification and listing of the evidence that relates to each settled issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

The parties agree that all positions, information, documents, negotiations and discussion of any kind whatsoever which took place or were exchanged during the Settlement Conference are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Proposal.

According to the Settlement Guidelines (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge Gas Distribution and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

Issues 1.1 to 1.8, 2.1, 2.2, 3.2, 3.5, 3.7 to 3.9, 3.11 to 3.15 and 9.1 have been settled by parties as a package (the “package”), subject to the objections of GEC, Pollution Probe and Schools, as noted earlier, and none of the parts of this package are severable. All parties agree that, for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company’s April 1, 2007 QRAM is implemented. GEC’s and Pollution Probe’s agreement in this regard is subject to any later adjustments to the Company’s recovery of revenue deficiency that might be required as a result of

Issue 3.2. Schools' agreement in this regard is subject to any later adjustments to the Company's recovery of revenue deficiency that might be required as a result of Issue 9.1. Subject to considering the objections of GEC, Pollution Probe and Schools during the hearing, if the Board does not, prior to the commencement of the hearing of the evidence in EB-2006-0034, accept the package in its entirety, then there is no Settlement Proposal (unless the parties agree that any portion of the package that the Board does accept may continue as part of a valid Settlement Proposal). None of the parties can withdraw from the Settlement Proposal except in accordance with Rule 32 of the Rules. Finally, unless stated otherwise, the settlement of any particular issue in this proceeding is without prejudice to the rights of parties to raise the same issue in any future proceeding.

OVERVIEW

In order to address certain issues that have continued to be the subject of debate and discussion over a number of years, and in order to satisfy Board directions from the Decision with Reasons in the EB-2005-0001 case (the 2006 rate case), during the past year the Company has entered into a number of consultative processes with stakeholders. These consultatives were convened in respect of EnVision (issues 1.5 and 1.6), Corporate Cost Allocation (issues 3.6 and 3.7), customer care and CIS (issues 3.2 and 7.1 to 7.4) and open bill access (issue 7.5). These consultative processes have contributed greatly to the ability of all parties to come to settlements on many of these issues, as set out below. Several of the consultative processes are ongoing and may lead to settlement of additional issues. If additional issues are partly or completely settled, parties propose to file a supplementary settlement agreement that would explain the settlements, and the incremental financial impacts of such settlements.

Parties have been able to agree upon the package, which includes settlement of many of the issues raised in this proceeding. While some issues remain outstanding and unresolved, the impact of this Settlement Proposal, if accepted, is that the scope and length of the proceeding will be substantially reduced.

The Company's Application sought recovery of a revenue deficiency of $167.8 million. This figure was updated to $158.7 million in Impact Statement No. 1, to account for, among other things, the ROE for the Test Year of 8.39%.

Parties have agreed upon the settlement package of issues that, if accepted, would reduce the revenue deficiency by $76.7 million. This would result in a remaining revenue /c
deficiency of $82.0 million. /c

The implementation of the settlement package of issues will result in a revenue deficiency of $29.9 million, based on the Company's filing which expresses the revenue deficiency /c
as being relative to the Board-approved rates for F2006, and all of the items that make up

and contribute to those rates including, for example, the agreed-upon level of degree days for F2006.

The issues that are not settled by the Settlement Proposal represent an additional revenue deficiency amount of $52.1 million, based on the Company's filing, which will /c require determination by the Board in the hearing. Based on positions that may be taken by parties in the hearing, the potential outcomes arising from the determination of these unsettled issues by the Board range from an incremental revenue sufficiency of approximately $5 million to an incremental revenue deficiency of $52.1 million. /c

Some intervenors assert that, if they are successful on outstanding issues (in particular issues related to Issue 2.2 regarding degree days), then there could be a revenue sufficiency in respect of those issues. Parties are able to agree, however, that for rate implementation purposes only, the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. This amount of $26.0 million will be subtracted from the total revenue deficiency resulting from the Board's final decision in this proceeding (which will include all impacts of this Settlement Proposal). The resulting revenue deficiency (or sufficiency) will be reflected and recovered in rates by the Company, subject to the outcome of Issue 9.1.

When implemented, the recovery of an additional $26.0 million will result in average increases, on an annual basis, of approximately 2% for Rate 1 customers, 1% for Rate 6 customers and between 0% and 2% increases for other rate classes. These average rate increases are relative to the July 1, 2006 QRAM rate and are calculated for a T-service customer, excluding commodity costs, and do not include impacts from the phase-in of cost allocation changes on October 1, 2006 and October 1, 2007. When these rate impacts are compared to the January 1, 2007 QRAM rate, the results are virtually identical as shown in Appendix B. The phase-in of cost allocation changes on October 1, 2007 will reduce the amounts recovered from Rate 1 and Rate 6 by approximately $5.01 million and $4.8 million respectively, and increase the amounts recovered from Rate 115, Rate 135 and Rate 170 by about $5.97 million, $0.6 million and $3.2 million respectively, as shown in Appendix B. The determination by the Board of the issues that are not settled will have additional rate impacts.

Attached as Appendix B is an approximation of the annual T-service rate increases that would result from the recovery of additional amounts of $26.0 million (the immediate additional amount to be recovered if the Settlement Proposal is accepted) and $82.0 /c million (the maximum recoverable revenue deficiency if the Settlement Proposal is accepted and the Board decides the unsettled issues by adopting the Company's position on these issues). These approximations do not take account of the clearance of deferral and variance accounts, the phase-in of cost allocation changes or any allocation changes that might result from the resolution of Issue 6.2. These average annual T-service rate impact estimates are not indicative of the percentage T-service rate increase that will occur on April 1, 2007, compared to T-service rates in force on March 31, 2007. T-service rate increases effective April 1, 2007 will include the rate increase associated with the nine month Rate Rider described in Issue 9.1. The Company believes, based on the analysis that it has undertaken, that these approximations of average annual T-service rate impacts, which are expressed relative to the July 1, 2006 QRAM rates and the January 1, 2007 QRAM rates, and are calculated for a T-service customer excluding commodity costs, are correct within +/- 0.5%.

1 RATE BASE (Exhibit B)

1.1 Are the amounts proposed for the 2007 Rate Base appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties have reached a global settlement of all 2007 Rate Base issues, except for issues related to the capital budget for the new CIS system. Issues related to the new CIS system are discussed below at Issues 7.2 to 7.4. The capital spending for the new CIS system will have no rate base impact in 2007. Parties agree that the Company will reduce the revenue deficiency associated with 2007 Rate Base issues by a total of $8 million, as compared to the Company's filed evidence. This will result in a 2007 capital budget of approximately $300 million, plus the cost of the Portlands Energy Centre Leave to Construct project, which is estimated at $18 million during the Test Year. The Portlands Energy Centre project, if approved in the leave to construct application, will not affect rates for the Test Year. Parties believe that the Board's consideration of the Portlands Energy Centre in the leave to construct application should be consistent with the principles set out under Issue 1.4 below.

Parties agree that the 2007 capital budget is an envelope amount, and the Company will have discretion to determine which items will be removed or changed from the Company's filed capital budget in order to reduce the overall level of that budget. Notwithstanding this discretion, the Company agrees that it will not proceed with the Automatic Meter Reading (AMR) project. Intervenors do not necessarily accept, and presently take no position on, the Company's decisions as to how it will allocate and spend the 2007 capital budget. Parties agree that, assuming the incentive regulation rate setting process allows for it, a normal review of the Company's capital spending in the Test Year may be undertaken as part of the rate setting process for 2008. The issue of capital spending on the EnergyLink program, included in Issue 3.4, is not settled, but the Board's decision on that issue will not affect the overall capital budget for the Test Year, only the Company's ability to allocate funds to EnergyLink within that budget. Parties accept the Company's opening rate base for 2007.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Utility Rate Base
B1-1-2	Utility Rate Base Year to Year Summary
B1-2-1	Rate Base Capital Budget
B3-1-1	Ontario Utility Rate Base – Comparison of 2007 Test Year to 2006 Bridge Year
B3-1-2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2007 Test Year
B3-1-3	Working Capital Summary of Average of Monthly Averages 2007 Test Year
B3-2-1	Utility Capital Expenditures Comparison Budget 2007 and Estimated 2006
B3-2-2	2007 Capital Expenditures by Project (Projects Exceeding $500,000)
B3-2-3	Gross Customer Additions and Average Cost per Customer Addition Budget 2007 and Estimated 2006
B3-2-4	System Expansion Portfolio – 2007
F3-1-3	Utility Rate Base 2007 Test Year
I-1-1 to 3	Board Staff Interrogatories 1 to 3
I-9-4 and 7	IGUA Interrogatories 4 and 7
I-16-1 to 3	SEC Interrogatories 1 to 3
I-24-5 to 7	VECC Interrogatories 5 to 7
L-9-1	Evidence of IGUA
M1-1-1	Impact Statement #1

1.2 Are the amounts proposed for Capital Expenditures in 2007 appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

See Issue 1.1.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-2-1	Rate Base Capital Budget
B1-2-2	Details of Capital Expenditure and Justification for Major Capital Projects over $500,000
B1-3-1	Safety & Integrity Initiatives
B1-3-2	Leave to Construct Projects
B1-4-1	Information Technology Capital Budget
B1-5-1	CIS Project
B1-6-1	EnVision Project
B1-7-1	Automated Meter Reading (AMR)
I-1-4 to 6	Board Staff Interrogatories 4 to 6
I-2-1 to 4	CCC Interrogatories 1 to 4
I-9-2 and 5 to 6	IGUA Interrogatories 2 and 5 to 6

I-16-4 to 10	SEC Interrogatories 4 to 10
I-24-8 to 12	VECC Interrogatories 8 to 12

1.3 Is the budget amount proposed in 2007 for Safety & Integrity projects appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

See Issue 1.1. The Company will determine the 2007 capital expenditures budget for Safety and Integrity projects within the envelope set out under Issue 1.1.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-3-1	Safety & Integrity Initiatives
I-1-7	Board Staff Interrogatory 7
I-2-5 to 7	CCC Interrogatories 5 to 7
I-9-8	IGUA Interrogatory 8
I-16-11 to 12	SEC Interrogatories 11 to 12
I-24-13	VEC Interrogatory 13

1.4 How should the Board deal with the Leave to Construct (“LTC”) projects included in the 2007 capital budget given that there will be separate Board Proceedings for the LTC projects?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties are of the view that the Board’s decisions determining the appropriate total amount of capital spending by the Company in any test period are most suitably made in a rate application. In general, parties agree that the Board’s decision with respect to overall capital spending does not imply specific approval of any individual leave to construct projects (“LTC Projects”), nor a decision as to the economic feasibility of any individual LTC Project. Similarly, parties agree that, generally, a decision with respect to the economic feasibility of an individual LTC

Project does not, in and of itself, imply that it is appropriate to include capital spending pertaining to that LTC Project in the capital budget for a test year used by the Board to establish rates.

In the context of the foregoing, the parties agree that the Board should deal with LTC Projects included in any test year capital budget as follows:

1. The total capital expenditures budget for a particular test year, to be considered and approved in a rate application, should include some evidence on individual LTC Projects planned for that year. However, the Board should not be asked to approve individual LTC Projects in a rate case. In a rate case, evidence with respect to individual LTC Projects need not be as extensive as the evidence required to support a LTC Application.

2. The economic feasibility of an individual project is considered in a leave to construct application. A LTC Application should not result in any adjustment to the Company's capital expenditures budget aside from exceptional circumstances, and in those cases the Board should consider and make the adjustment expressly.

3. A LTC Application can be heard by the Board prior to its consideration of the capital budget consequences of the LTC Project in a rates proceeding. In the event the Board approves a LTC Application, it will not be necessary to examine the justification for the LTC Project in a subsequent rate proceeding although the issue of the appropriate size of the overall capital budget would remain in issue in that hearing, and the leave to construct approval could inform that decision.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-3-2	Leave to Construct Projects
I-1-8 to 9	Board Staff Interrogatories 8 to 9
I-2-8	CCC Interrogatory 8
I-9-9	IGUA Interrogatory 9
I-16-13 to 14	SEC Interrogatories 13 to 14
I-19-4	TransAlta Interrogatory 4

1.5 Has the Company met the requirements of the Board's directive from the 2006 rate case to file an independent cost benchmark study for the EnVision project?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that the Company has met the requirements of the Board's directive from the EB-2005-0001 Decision with Reasons by filing an independent cost benchmark study for the EnVision project.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B2-2-1	Compass Report – Envision Cost Benchmark Analysis
B1-6-1	EnVision Project

1.6 What are the appropriate EnVision cost and benefits and how should they be reflected in 2007 rates?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that Compass carried out an appropriate cost benchmark study of the EnVision Project. Parties differ on how that benchmark should be applied in determining the costs and benefits associated with EnVision that should be reflected in rates. In order to resolve the EnVision issues in this proceeding, the Company has agreed to reduce the revenue requirement by $500,000 through a reduction in the 2007 Other O&M budget. This reduction is reflected and included in the $181.5 million total Other O&M budget agreed to below at Issue 3.2. The Company will continue to report annually to stakeholders on the achievement of EnVision benefits in the form and the manner set out in Tables 1 and 2 in Exhibit B1/T6/S1/pp 8-9. Parties agree that unless there is a change in the overall NPV of the EnVision project, there will be no need to revisit the EnVision project in future regulatory proceedings.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B2-2-1	Compass Report – Envision Cost Benchmark Analysis
B1-6-1	EnVision Project
1-2-9 to 17	CCC Interrogatories 9 to 17
1-16-15	SEC Interrogatory 15

1.7 Is the business case, including the total project amount of $133 million, proposed for the Automatic Meter Reading project ("AMR") justified?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

As part of the global settlement of 2007 rate base issues, the Company agrees not to proceed with the AMR project.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-7-1	Automated Meter Reading (AMR)
I-1-10 to 13	Board Staff Interrogatories 10 to 13
I-2-18 to 22	CCC Interrogatories 18 to 22
I-9-11	IGUA Interrogatory 11
I-16-16	SEC Interrogatory 16
I-24-14	VECC Interrogatory 14

1.8 Is the proposed recovery of AMR costs in 2007 rates appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

As part of the global settlement of 2007 rate base issues, the Company agrees not to proceed with the AMR project. As a result, this issue is no longer relevant.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B1-7-1	Automated Meter Reading (AMR)
1-24-15 to 16	VECC Interrogatories 15 to 16

2 OPERATING REVENUE (Exhibit C)

2.1 Is the proposed amount for 2007 Transactional Services revenue appropriate, and is the associated sharing mechanism in accordance with the 2006 decision?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that the Company will share net transactional services revenues with ratepayers on a 75:25 basis in favour of ratepayers for transportation-related transactional services and on a 90:10 basis in favour of ratepayers for storage-related transactional services. The Company agrees to credit $8 million in transactional services revenue to ratepayers, to be credited to the revenue requirement for the purpose of setting rates for the Test Year. This credit will not be allocated as between transportation and storage transactional services. The 2007 Transactional Services Deferral Account will include the total of the ratepayers' shares of the net transactional services revenue for transportation-related and for storage-related transactional services, less the $8 million credit and the O&M costs associated with storage-related transactional services (estimated at $.1 million in the Company's updated evidence at Ex. C1-4-2). For greater certainty, if the result of these calculations is that the year-end balance in the 2007

Transactional Services Deferral Account would be less than zero, the balance shall be deemed to be zero.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-4-1	Transactional Services Revenue
C1-4-2	Transactional Services – Supplementary Evidence
I-1-14 to 15	Board Staff Interrogatories 14 to 15
I-2-23	CCC Interrogatory 23
I-9-13	IGUA Interrogatory 13
1-16-17	SEC Interrogatory 17
I-24-17 to 18	VECC Interrogatory 17 to 18
M1-1-1	Impact Statement #1

2.2 Is the proposed total 2007 Other Revenue Forecast appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree to increase the forecast for Other Operating Revenue for the Test Year from $23.7 million to $28.9 million, inclusive of the $3.5 million incremental impact of the resolution of the Transactional Services issue (described above at Issue 2.1), an increase of $1.0 million from the forecast of Other Service Revenues in the Company's evidence and the imputation of revenue of $700,000 for the Natural Gas Vehicles (NGV) program for the Test Year (in order to reflect the revenue deficiency of the NGV program).

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-5-1	Other Service and Late Payment Penalty Revenues
C3-5-1	Rate of Return on Capital Employed in the Natural Gas Vehicles Program

I-1-16	Board Staff Interrogatory 16
I-2-24 to 25	CCC Interrogatories 24 and 25
I-16-18	SEC Interrogatory 18
I-24-19 to 22	VECC Interrogatories 19 to 22
M1-1-1	Impact Statement No. 1
M1-2-5	Change in Revenue Requirement

2.3 Is the forecast of degree days appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C2-4-1	Budget Degree Days
I-1-17	Board Staff Interrogatory 17
I-9-3 and 14	IGUA Interrogatories 3 and 14
1-5-1 to 12	Energy Probe Interrogatories 1 to 12
1-16-19 to 20	SEC Interrogatories 19 to 20
L-9-1	Evidence of IGUA

2.4 Are the average use-per-customer forecasts for rate class 1 and rate class 6 appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
C2-3-1	Average Rate Use 1
C2-3-2	Average Use Rate 6
I-1-18	Board Staff Interrogatory 18
I-2-26 to 28	CCC Interrogatories 26 to 28
I-16-21 to 23	SEC Interrogatories 21 to 23
I-24-22 to 25	VECC Interrogatories 22 to 25

2.5 Is the proposed 2007 contract gas volume and revenue forecast appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
I-1-19	Board Staff Interrogatory 19
I-1-12	IGUA Interrogatory 12

2.6 Is the proposed 2007 General Service gas volume and revenue forecast appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

C1-3-1	Volume Budget
C1-1-1	Operating Revenue Summary
C1-2-1	Revenue Forecast
C3-1-1	Utility Operating Revenue 2007 Test Year
C3-1-2	Comparison of Utility Operating Revenue Budget 2007 and Estimate 2006
I-1-20	Board Staff Interrogatory 20
1-24-23 to 25	VECC Interrogatories 23 to 25

3 OPERATING COST (Exhibit D)

3.1 Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's forecast of the cost consequences of the gas supply portfolio for the Test Year.

The Company agrees with certain parties that, when the issues list for the Natural Gas Forum proceeding about QRAM methodology is discussed, the Company will support the inclusion of an issue regarding the detailed calculation of the PGVA Reference Price.

Participating Parties: All parties participated in the negotiation and settlement of this issue except GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Cost of Gas, Transportation and Storage
D1-4-2	Status of Contracts
D3-3-1	Summary of Gas Cost to Operations
D3-3-2	Summary of Gas Storage and Transportation Costs Fiscal 2007
D3-3-3	Canadian Peak Day Supply Mix
D3-3-4	Monthly Pricing Information
D3-3-5	Gas Supply/Demand
I-1-21	Board Staff Interrogatory 21
I-2-29	CCC Interrogatory 29
I-5-16 to 17	Energy Probe Interrogatory 16 to 17
I-9-16	IGUA Interrogatory 16
I-18-6	Superior Interrogatory 6
I-21-1 to 9	TransCanada Interrogatories 1 to 9
I-24-26	VECC Interrogatory 26

3.2 Is the overall level of the 2007 Operation and Maintenance Budget appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

The Company's overall Operations and Maintenance (O&M) budget, as filed in Impact Statement No. 1, for the Test Year totalled $365.8 million and can be divided into a number of categories: (i) customer care expenses (including CIS, internal costs and provision for uncollectibles) – filed as $120.1 million; (ii) corporate cost allocations – filed as $22.9 million; (iii) demand side management (DSM) programs – filed as $22.0 million; and (iv) Other O&M – filed as $200.8 million. The Company has also included transition costs of $10 million related to customer care as a separate line item in its filing.

Issues related the Company's customer care O&M budget (including the transition costs) are discussed below at Issues 7.1 to 7.4. Parties, except for GEC and Pollution Probe, agree on the balance of the Company's O&M budget for the Test Year.

Parties acknowledge that the Company's O&M DSM budget for the Test Year shall be $22.0 million, as set out in the Board's Decision with Reasons in EB-2006-0021 (the DSM generic hearing).

Parties agree that the Company's O&M budget for corporate cost allocations for the Test Year shall be $18.1 million. Parties agree to the overall level of this budget, but there is no specific agreement as to the amounts of each of the individual allocations. The issues about the corporate cost allocation methodology set out in Issue 3.6 remain unsettled.

Parties, except for GEC and Pollution Probe, agree that the Company's Other O&M budget for the Test Year, filed as $200.8 million, shall be reduced by $19.3 million to $181.5 million. Subject to the comments below, parties agree that the amount of the Other O&M budget is an envelope amount and the Company will have discretion to determine which items will be removed or changed from the Company's Other O&M budget as filed in order to reduce the overall level of that budget. Intervenors do not necessarily accept, and presently take no position on, the Company's decisions as to how it will allocate and spend the 2007 Other O&M budget.

Notwithstanding the agreement on the overall level of the Company's Other O&M budget for the Test Year, parties agree that certain components of the Company's Opportunity Development planned activities for the Test Year, specifically marketing activities, fuel switching and EnergyLink, will be examined before the Board. Parties, except for GEC and Pollution Probe, agree that the examination of those sub-issues before the Board will not impact on the $181.5 million agreed-upon level of the Other O&M budget for the Test Year. Subject to the exception set out below, parties other than GEC and Pollution Probe agree that they will not take any position in this proceeding on how the Company ought to allocate the agreed-upon $181.5 million Other O&M budget. Notwithstanding the foregoing, in the event that the Board determines that the Company may not proceed with EnergyLink, it is understood that Schools and/or HVAC may advance arguments about how the Company ought to spend the O&M amounts totaling $1.3 million (Ex. I-26-4) that were otherwise budgeted for EnergyLink. Notwithstanding the foregoing, it is also understood that VECC may advance arguments that the Company ought to allocate funds as budgeted of $925,000 to low income fuel switching (Ex. 1-24-29). Additionally, the Company agrees that from and after the date of the Board's decision in this proceeding, it will not allocate any portion of the agreed-upon $181.5 million Other O&M budget to any specific marketing, fuel switching or EnergyLink activities that the Board specifically states the Company should not be undertaking.

GEC and Pollution Probe do not agree to the $181.5 million Other O&M budget. GEC and Pollution Probe wish to examine the Company's Opportunity Development (OD) O&M budget separately and do not agree to the overall level of $181.5 million for the Other O&M budget. No other parties, including the Company, will support or argue for any change (increase or decrease) to the agreed-upon Other O&M budget of $181.5 million.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, OAPPA, OESLP, Superior, TransCanada, TransAlta, Union Gas.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue except Pollution Probe and GEC.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
D1-2-1	Operating, Maintenance and Other Costs
D2-1-1	Corporate Cost Allocation
D3-1-1	Operating Cost 2007 Test Year
D3-2-1	Operating Cost Comparison of Utility Cost and Expenses Budget 2007 and Estimate 2006
D3-2-2	Operating and Maintenance Expense by Department
D3-2-3	Operating and Maintenance Expense by Cost Type
I-1-22 to 24	Board Staff Interrogatories 22 to 24
I-2-30 to 35	CCC Interrogatories 30 to 35
I-9-2, 4 and 15	IGUA Interrogatories 2, 4 and 15
I-15-1 to 4	Pollution Probe Interrogatories 1 to 4
I-16-24 to 29	SEC Interrogatories 24 to 29
I-24-27 to 28	VECC Interrogatories 27 to 28
L-9-1	Evidence of IGUA
M1-1-1	Impact Statement #1

3.3 Is the Company's proposed fuel switching program appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-8-1	Opportunity Development – Market Development
I-1-25	Board Staff Interrogatory 25
I-2-36 to 39	CCC Interrogatories 36 to 39
I-7-1	GEC Interrogatory 1
I-22-6	Union Energy Interrogatory 6
I-24-29	VECC Interrogatory 29
I-26-1 to 3	HVAC Interrogatory 1 to 3

3.4 Is the Company's proposed Energy Link program appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Operating Cost Summary
I-22-6	Union Energy Interrogatory 6
I-24-30	VECC Interrogatory 30
I-26-4 to 10	HVAC Interrogatories 4 to 10
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-36 to 46	Enbridge Gas Distribution Interrogatories of Union Energy 36 to 46
I-30-1 to 21	Enbridge Gas Distribution Interrogatories of HVAC 1 to 21

3.5 Is the budget for Human Resources related costs appropriate?

(Complete Settlement)

There is an agreement to settle this issue as part of the package, as follows:

> Parties agree that any Human Resources related costs determined by the Company to be appropriate in the Test Year will be included as part of the agreed-upon $181.5 million Other O&M budget.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Costs and Maintenance and Other Costs
D1-2-2	Employee Expenses and Workforce Demographics
D3-2-4	Salaries and Wages and FTE Forecast 2007 Test Year
I-1-26	Board Staff Interrogatory 26
I-2-40 to 43	CCC Interrogatories 40 to 43
I-16-30 to 37	SEC Interrogatories 30 to 37
I-24-31 to 33	VECC Interrogatories 31 to 33

3.6 Do the revisions to the Regulatory Cost Allocation Methodology (RCAM) meet the Board's directives in the 2006 decision?

(No Settlement)

There is no agreement to settle this issue.

The issue of whether the revisions to RCAM meet the Board's directives from the 2006 decision has been a subject of the corporate cost allocation consultative. At this time, the final report from the consultant retained on behalf of the consultative has not been filed. As a result, no settlement can be reached on this issue at this time.

Evidence: The evidence in relation to this issue includes the following:

D2-1-1	Corporate Cost Allocation
G1-1-1	Corporate Cost Allocation Methodology
I-16-38 to 39	SEC Interrogatories 38 to 39

3.7 Is the proposed level of corporate cost allocation for 2007 appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties agree that the Company's O&M budget for corporate cost allocations for the Test Year shall be $18.1 million. Parties agree to the overall level of this budget, but there is no specific agreement as to the amounts of each of the individual allocations.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Maintenance and Other Costs
D2-1-1	Corporate Cost Allocation
I-1-27 to 28	Board Staff Interrogatories 27 to 28
I-9-1	IGUA Interrogatory 1
I-24-34 to 37	VECC Interrogatories 34 to 37

3.8 Is Company's forecast level of Regulatory and OEB related costs for 2007 appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Parties agree that the Company's Regulatory and OEB related costs will be included as part of the agreed-upon Other O&M budget and that variances from the budget for 2007 rate proceeding related expenses will be recorded in the 2007 Ontario Hearings Costs Variance Account for consideration and disposition in a future proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-2-1	Operating Maintenance and Other Costs
D1-9-1	Regulatory Costs
I-1-29 to 30	Board Staff Interrogatories 29 to 30
I-2-44	CCC Interrogatory 44
I-16-40	SEC Interrogatory 40

3.9 Is Enbridge's decision to change to a December 31 taxation year-end , in 2007, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> Intervenors have relied on the Company's evidence that the change of taxation year-end for the Enbridge Gas Distribution Inc. corporate entity has no impact on the Company's 2007 cost of service. In conjunction with the agreement with respect to Issue 3.15, intervenors accept the Company's evidence in this regard.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-5-1	Taxation Year-End Change

I-1-31 to 34	Board Staff Interrogatories 31 to 34
I-16-41	SEC Interrogatory 41

3.10 Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-4-3	Gas Supply Risk Management
I-1-35 to 36	Board Staff Interrogatories 35 to 36
I-2-45	CCC Interrogatory 45
I-5-18 to 27	Energy Probe Interrogatories 18 to 27
I-18-7	Superior Interrogatory 7
I-24-38 to 39	VECC Interrogatories 38 to 39
L-5-1	Evidence of Energy Probe
I-36-1 to 6	Enbridge Gas Distribution Interrogatories of Energy Probe 1 to 6

3.11 Is the proposal to change depreciation rates for 2007, as proposed in the depreciation study, and the impact on 2007 customer rates, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

> The Company agrees not to proceed with its request to change depreciation rates for 2007. Intervenors agree not to challenge the Company's existing depreciation rates for 2007. Notwithstanding this agreement, parties may examine the existing level of the Company's depreciation rates in the context of discussing and examining other outstanding issues in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-13-1	Depreciation Rate Change
D2-2-1	Depreciation Study

I-1-37 to 46	Board Staff Interrogatories 37 to 46
I-5-13 to 14	Energy Probe Interrogatories 13 to 14
I-9-18	IGUA Interrogatory 18
I-16-42 to 41	SEC Interrogatories 42 to 43
I-24-39.1 to 39.3	VECC Interrogatories 39.1 to 39.3
L-9-1	Evidence of IGUA

3.12 Is the proposal for the establishment of 2007 Deferral and Variance Accounts appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

The Company's proposal to establish the following deferral and variance accounts for the Test Year is accepted by the parties for the reasons set out in the Company's evidence:

2007 Purchased Gas Variance Account ("2007 PGVA")
2007 Transactional Services Deferral Account ("2007 TSDA")
2007 Unaccounted for Gas Variance Account ("2007 UAFVA")
2007 Union Gas Deferral Account ("2007 UGDA")
2007 Class Action Suit Deferral Account ("2007 CASDA")
2007 Debt Redemption Deferral Account ("2007 DRDA")
2007 Deferred Rebate Account ("2007 DRA")
2007 Gas Distribution Access Rule Costs Deferral Account ("2007 GDACRDA")
2007 Manufactured Gas Plant Deferral Account ("2007 MGPDA")
2007 Ontario Hearing Costs Variance Account ("2007 OHCVA")
2007 Electric Program Earnings Sharing Deferral Account ("2007 EPESDA")
2007 Unbundled Rate Implementation Cost Deferral Account ("2007 URICDA")
2007 Unbundled Rates Customer Migration Deferral Account ("2007 URCMDA")
2007 Demand-Side Management Variance Account ("2007 DSMVA")
2007 Lost Revenue Adjustment Mechanism ("2007 LRAM")
2007 Shared Savings Mechanism Variance Account ("2007 SSMVA")
2007 Income Tax Rate Change Variance Account ("2007 ITRCVA")

There is no agreement to the establishment of the following deferral and variance accounts, as those accounts are being dealt with as part of the customer care/CIS consultative process and through Issues 7.2 to 7.4:

2007 Customer Information System Procurement Deferral Account ("2007 CISPDA")
2007 Customer Care Procurement Deferral Account ("2007 CCPDA")
2007 Customer Care Supplier Transition Variance Account ("2007 CCSTVA")

There is no agreement to the establishment of the following deferral account, as it is being dealt with as part of the open bill consultative process and through Issue 7.5:

2007 Open Bill Access Sharing Deferral Account ("2007 OBASDA")

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Deferral and Variance Accounts
D1-7-3	Deferral and Variance Account Balances
I-1-47	Board Staff Interrogatory 47
I-2-46 to 48	CCC Interrogatories 46 to 48
I-7-2	GEC Interrogatory 2

3.13 Is the proposal for the disposition of existing Deferral and Variance Accounts appropriate?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

Enbridge Gas Distribution filed a summary of the actual deferral account and variance account balances for F2006 (D1-7-3); the summary is reproduced in Appendix A. The result of clearing certain of these accounts is that Enbridge Gas Distribution will credit customers $23.258.7 million in principal plus interest, based upon the December 31, 2006 balances, for F2006.

The balances recorded in the following deferral and variance accounts established for F2006, and the proposed clearance of such balances at the same time as the final rate order in this proceeding is implemented, are accepted by the other parties for the reasons given in the supporting evidence:

Non Commodity Related Accounts

2004 Demand-Side Management Variance Account ("2004 DSMVA")
2004 Lost Revenue Adjustment Mechanism ("2004 LRAM")
2004 Shared Savings Mechanism Variance Account ("2004 SSMVA")
2006 Deferred Rebate Account (“2006 DRA”)
2006 Debt Redemption Deferral Account (“2006 DRDA”)
2006 Ontario Hearing Costs Variance Account (“2006 OHCVA”)

Commodity Related Accounts

2006 Unaccounted for Gas Variance Account (“2006 UAFVA”)
2006 Transactional Services Deferral Account (“2006 TSDA”)

2006 Union Gas Deferral Account ("2006 UGDA")

Enbridge Gas Distribution does not seek to clear, in the Test Year, the balances recorded in the following deferral and variance accounts. Parties agree that the following previously-approved deferral and variance accounts are continued and the clearance of these accounts will be addressed by the Board in the future.

<u>Non Commodity Related Accounts</u>

2006 Demand-Side Management Variance Account ("2006 DSMVA")
2005 Demand-Side Management Variance Account ("2005 DSMVA")
2006 Lost Revenue Adjustment Mechanism ("2006 LRAM")
2005 Lost Revenue Adjustment Mechanism ("2005 LRAM")
2006 Shared Savings Mechanism Variance Account ("2006 SSMVA")
2005 Shared Savings Mechanism Variance Account ("2005 SSMVA")
2006 Manufactured Gas Plant Deferral Account ("2006 MGPDA")
2006 Corporate Cost Allocation Deferral Account ("2006 CCAMDA")
2006 Class Action Suit Deferral Account ("2006 CASDA")

<u>Commodity Related Account</u>

2006 Purchased Gas Variance Account ("2006 PGVA")

While Enbridge Gas Distribution seeks to clear the balances recorded in the following deferral and variance accounts in the Test Year, there is no agreement as to whether this is appropriate and these accounts will be addressed at the hearing:

2006 Gas Distribution Access Rule Costs Deferral Account ("2006 GDARCDA")
2005 Gas Distribution Access Rule Costs Deferral Account ("2005 GDARCDA")
2006 Alliance Vector Appeal Costs Deferral Account ("2006 AVACDA")
2006 Gas Supply Risk Management Program Deferral Account ("2006 GSRMPDA")
2006 Electric Program Earnings Sharing Deferral Account ("2006 EPESDA")
2006 Unbundled Rate Implementation Cost Deferral Account ("2006 URICDA")

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-7-1	Deferral and Variance Accounts
D1-7-2	Proposed Clearing of the 2006 Deferral Accounts
D1-7-3	Deferral and Variance Account Balances
A1-13-1	Status of Board Directives from Previous Board Decisions and/or Orders
A3-3-1	Financial Statements – Enbridge Gas Distribution Historical 2005 Year

A3-4-1	Annual Report (Actual) and Management Discussion and Analysis (MD&A)
I-2-49	CCC Interrogatory 49
I-16-44 to 45	SEC Interrogatories 44 to 45
I-24-40	VECC Interrogatory 40

3.14 Are the amounts proposed to be included in rates for capital and property taxes appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

The Company agrees to a $1.3 million reduction in its forecast of municipal property and other taxes for the Test Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

D3-1-1	Operating Cost 2007 Test Year
I-9-3	IGUA Interrogatory 3
I-2-50	CCC Interrogatory 50

3.15 Is the amount proposed to be included in rates for income taxes, including the methodology, appropriate?

(Complete Settlement)

There is an agreement to settle this issue, as part of the package, as follows:

Parties accept the Company's methodology for income taxes, and the amount to be included in rates for income taxes, for the purpose of setting rates for the Test Year, without prejudice to the ability of any party to raise issues with respect to the methodology and its resulting calculations, including but not limited to which inclusions and deductions are appropriate, in future rate proceedings. The Company agrees to create a 2007 Income Tax Rate Change Variance Account to capture the impact of any corporate income tax rate changes against Fiscal 2007 Board Approved taxable income (versus the Company's forecast of corporate income tax rates) that occur in 2007 as a result of Provincial and Federal government budgets that are passed in the Test Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

A3-2-1	Financial Statements – Utility Proforma Statements for Bridge and Test Year
A3-3-1	Financial Statements – Enbridge Gas Distribution Historical 2005 Year
A3-4-1	Annual Report (Actual) and Management Discussion and Analysis (MD&A)
A3-5-3	Annual/Audited Financial Reports (Historical) Enbridge Inc. – 2005 Year
D3-1-1	Operating Cost 2007 Test Year
I-16-46 to 47	SEC Interrogatories 46 to 47

4 COST OF CAPITAL (Exhibit E)

4.1 What is the Return on Equity (ROE) for EGDI for the 2007 test year as calculated pursuant to the ROE Guidelines?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties agree that the ROE for the Company for the 2007 test year is 8.39%, as calculated pursuant to the ROE guidelines.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E2-1-1	Utility Business and Financial Risks
E2-1-2	Enbridge Gas Distribution Utility Business Risks – Environment
E2-1-3	Utility Equity Thickness Financial Risk Update
E2-2-1	Calculation of ROE

E3-1-1	Cost of Capital 2007 Test Year
E3-1-2	Summary Statement of Principal and Carrying Costs of Term Debt 2007 Test Year
E3-1-3	Unamortized Debt Discount and Expense Average of Monthly Averages 2007 Test Year
E3-1-4	Preference Shares Summary Statement of Principal and Carrying Cost 2007 Test Year
E3-1-5	Unamortized Preference Share Issue Expense Average of Monthly Averages 2007 Test Year
E3-1-6	Fiscal 2007 Calculation of Short-term Unfunded Debt
I-5-15	Energy Probe Interrogatory 15
I-24-41 to 43	VECC Interrogatories 41 to 43
M1-1-1	Impact Statement #1

4.2 Are Enbridge's proposed costs for its debt and preference share components of its capital structure appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
I-1-48	Board Staff Interrogatory 48
I-16-48 to 50	SEC Interrogatories 48 to 50

4.3 Is the proposal to change the equity component of the deemed capital structure from 35% to 38% appropriate?

(No Settlement)

There is no agreement to settle this issue.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Cost of Capital Summary
E1-2-1	Cost of Capital
E2-1-1	Utility Business and Financial Risks
E2-1-2	Utility Equity Thickness Financial Risk Update
E2-1-2	Enbridge Gas Distribution Utility Business Risks – Environment
E2-2-1	Calculation of ROE
E3-1-1	Cost of Capital 2007 Test Year
I-2-51	CCC Interrogatory 51
I-9-19	IGUA Interrogatory 19
I-16-51 to 54	SEC Interrogatories 51 to 54
I-24-44 to 57	VECC Interrogatories 44 to 57
I-24-77 to 83	VECC Supplementary Interrogatories 77 to 83
L-9	Evidence of IGUA
L-27-1	Evidence of VECC, CCC and IGUA
L-27-2	Supplementary Evidence of VECC, CCC and IGUA
I-28-1 to 17	Enbridge Gas Distribution Interrogatories of VECC, CCC and IGUA 1 to 17

5 COST ALLOCATION (Exhibit G)

5.1 Is the Applicant's cost allocation appropriate and is it based in its 2006 Board approved methodology?

(Complete Settlement)

There is an agreement to settle this issue as follows:

> Subject to the comments below in respect of Issues 6.2, 6.4 and 8.1, and subject to a compliance review of the cost allocation that will be embedded in any rate orders arising from this proceeding, parties accept the Company's evidence in this proceeding about its cost allocation for the Test Year and agree that it is appropriate and consistent with the 2006 Board-approved methodology.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransAlta, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	Cost Allocation Methodology
G2-1-1	Fully Allocated Cost Study
I-1-52	Board Staff Interrogatory 52
I-9-20	IGUA Interrogatory 20
I-24-59	VECC Interrogatory 69

5.2 Is the proposal to recover Demand Side Management costs in delivery charges, as opposed to load balancing charges, appropriate?

(Complete Settlement)

There is an agreement to settle this issue as follows:

> Parties accept the Company's proposal, as set out in the evidence, to recover Demand Side Management costs in delivery charges, rather than in load balancing charges.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

G2-3-1	Functionalization of Utility Rate Base
G2-3-2	Functionalization of Utility Working Capital
G2-3-3	Functionalization of Utility Net Investments
G2-3-4	Functionalization of Utility O&M
I-1-53	Board Staff Interrogatory 53

6 RATE DESIGN (Exhibit H)

6.1 Is the proposal to introduce delivery demand charges for Rates 100 and 145 reasonable?

(Complete Settlement)

There is an agreement to settle this issue as follows:

Parties accept the Company's proposal, as set out in the evidence, to introduce delivery demand charges for Rates 100 and 145.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue except TransAlta and VECC, which take no position.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook
H2-7-1	Annual Bill Comparison
H3-1-1	Revenue Comparison – Current vs Proposed by Rate Class Proposed Methodology
H3-1-2	Proposed Unit Rates by Rate Class
H3-2-1	Proposed Revenue Recovery by Rate Class

H3-3-1	Summary of Proposed Rate Change
H3-4-1	Calculation of Gas Supply Charges by Rate Class
H3-5-1	Detailed Revenue Calculations by Rate Class
H3-6-1	Rate Handbook
H3-7-1	Annual Bill Comparison
I-1-54	Board Staff Interrogatory 54
I-12-1	OAPPA Interrogatory 1

6.2 Is the proposal to allocate revenue requirement between the customer classes and annually adjust the monthly customer charges and variable charges to recover the revenue deficiency reasonable?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue as follows:

Parties accept the Company's proposal, as set out in the evidence, to annually adjust the monthly customer charges and variable charges to recover the revenue deficiency.

There is no agreement about the Company's proposal to allocate revenue requirement between customer classes. Some parties are concerned that the allocation of the 2007 revenue deficiency as proposed in the Company's evidence results in the collection of revenues greater than allocated costs from Rate 1 and Rate 6 customers based on the Company's filed Revenue to Cost ratios of 1.02 and 1.01 for these rate classes. These parties wish to explore the proposed 2007 revenue requirement allocation in light of the evidence and interrogatory responses on this issue. Other parties support the Company's revenue deficiency allocation and will oppose changes to it.

Participating Parties: All parties participated in the negotiation and settlement of aspects of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada**.**

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-1-1	Revenue Comparison – Current Revenue vs. Proposed Revenue
H2-2-1	Proposed Revenue Recovery by Rate Class
H2-3-1	Summary of Proposed Rate Change by Rate Class
H2-4-1	Calculation of Gas Supply Charges by Rate Class
H2-5-1	Detailed Revenue Calculations by Rate Class
H2-6-1	Rate Handbook

H2-7-1	Annual Bill Comparison
H3-1-1	Revenue Comparison – Current vs Proposed by Rate Class Proposed Methodology
H3-1-2	Proposed Unit Rates by Rate Class
H3-2-1	Proposed Revenue Recovery by Rate Class
H3-3-1	Summary of Proposed Rate Change
H3-4-1	Calculation of Gas Supply Charges by Rate Class
H3-5-1	Detailed Revenue Calculations by Rate Class
H3-6-1	Rate Handbook
H3-7-1	Annual Bill Comparison
I-1-55	Board Staff Interrogatory 55
I-9-23	IGUA Interrogatory 23
I-12-2	OAPPA Interrogatory 2
I-24-70	VECC Interrogatory 70

6.3 Should the Board approve the contents of the Applicant's Rate Handbook?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue as follows:

> Parties agree that it is appropriate for the Board to continue to approve the Company's Rate Handbook, as part of the Rate Order resulting from Rate Case proceedings.
>
> There is no agreement on the Company's proposed Invoice Vendor Adjustment (IVA) charge.
>
> Subject to the issue about the IVA, parties agree that the Rate Handbook as filed should be approved by the Board.

Participating Parties: All parties participated in the negotiation and settlement of this issue except GEC, HVAC, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-14-1	Policies and Regulations of the Company with Respect to Gas Services and Schedule of Service Charges
A1-14-2	Changes to the Schedule of Service Charges
D1-10-2	Gas Distribution Access Rule
H1-1-1	Rate Design
H2-6-1	Rate Handbook
I-19-1	TransAlta Interrogatory 1
I-1-56	Board Staff Interrogatory 56
I-12-3	OAPPA Interrogatory 3
I-24-71 to 73	VECC Interrogatories 71 to 73

6.4 Is the proposed treatment of bundled transportation charges and T-service credit appropriate in light of the Board's Decision in RP-2003-0203 and the settlement agreement?

(Complete Settlement)

There is agreement to settle this issue as follows:

Parties accept the Company's proposed treatment of bundled transportation charges and T-service credits. The final rate increases associated with the implementation of the settlement proposal of the changes in the allocation of upstream transportation charges in EB-2005-0001 will be implemented on October 1st, 2007. Effective October 1, 2007, the upstream transportation charges for all rate classes will recover the appropriate level of upstream transportation costs for all rate classes, so that there will be no over-contribution from Rates 1 and 6 with respect to upstream transportation costs.

The Company will continue to charge and rebate the T-service credit for Ontario T-Service customers. The existing T-Service credit, equal to TransCanada's 100% load factor toll, will continue to be in effect until December 31, 2007. Effective January 1, 2008, the T-Service credit will be based on the weighted average cost of transportation, equal to the unit rate based on total utility transportation costs over total delivery volumes. The Company will treat T-Service credits for Ontario T-Service customers in this manner, as an "off-set", from January 1, 2008 until such time as the Company has a new billing system that permits a different approach. This approach satisfies the Board's directive regarding the Company's obligation to phase-out the T-service credit for Ontario T-Service customers as outlined in the RP-2003-0203 Settlement Proposal.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
I-1-57	Board Staff Interrogatory 57
I-12-4	OAPPA Interrogatory 4

7 CUSTOMER CARE SUPPORT, CUSTOMER CARE SYSTEM, AND OPEN BILL ACCESS

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

D1-12-1	Customer Care - Overview
D1-12-2	Customer Care and Transition Costs
D1-12-3	Customer Care – Benchmarking
I-1-58	Board Staff Interrogatory 58
I-9-17	IGUA Interrogatory 17
I-16-55 to 58	SEC Interrogatories 55 to 58

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

D1-10-1	GDAR
I-1-59	Board Staff Interrogatory 59

7.3 Are the forecast costs of the new CIS system appropriate?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

B1-5-1	CIS Project
I-1-60 to 63	Board Staff Interrogatories 60 to 63
I-9-10	IGUA Interrogatory 10
I-26-11	HVAC Interrogatory 11

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs?

(No Settlement)

Issues related to customer care and CIS are the subject of continuing discussions as part of a consultative process involving the Company and stakeholders. Negotiations are continuing as part of the consultative process and parties expect to be able to report their progress and positions to the Board at the same time as the Settlement Proposal is presented for approval.

Evidence: The evidence in relation to this issue includes the following:

B1-5-1	CIS Project
D1-12-1	Customer Care – Overview
D1-12-2	Customer Care and Transition Costs
D1-12-3	Customer Care – Benchmarking
D3-2-1	Operating Cost Comparison of Utility Cost and Expenses Budget 2007 and Estimate 2006
I-1-64 to 73	Board Staff Interrogatories 64 to 73
I-16-59	SEC Interrogatory 59

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(No Settlement)

There is no agreement to settle this issue, although the consultative is ongoing.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007
D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006
D1-11-19	Presentation – November 30th, 2006
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D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5

I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference

8 OTHER ISSUES

8.1 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the NGEIR (EB-2005-0551) proceeding will be appropriately captured and reflected in this proceeding?

(Complete Settlement)

There is an agreement to settle this issue as follows:

All parties agree that the implications of the Board's decisions in the NGEIR (EB-2005-0551) proceeding have been captured in the Company's filing in this proceeding. This agreement is subject to the stipulation that certain parties have initiated Motions for Review of the Board's decisions in the NGEIR proceeding which, if successful, could require the Company to make consequential adjustments to its rates, including (without limitation) Rate 316.

The Company's obligations under the NGEIR Settlement Proposal pertaining to whether and when an automated solution should be developed and put in place remain in full force and effect.

Every three months the Company will provide to stakeholders a report on the number of customers that have committed to migrate and have migrated to the new unbundled Rates 300 and 315. If, at any time during the Test Year, 20 customers have committed to take EGD's unbundled rates, the Company will undertake a survey, using the least cost approach, to evaluate demand for unbundled Rates 300 and 315, and assess and report on the timing for development of an automated solution and accommodating additional customers through the manual solution within 90 days after the Company's 20th customer has committed to migrate to the new unbundled rates. If, at that time, the Company decides to proceed with a manual solution, it will continue to provide customers with a quarterly report on the status of migration including feedback from customers on the potential for future migration. The parties agree that the Company's costs associated with preparing and administering the survey will be recorded in the 2007 Unbundled Rate Implementation Cost Deferral Account. The parties further agree they will support recovery by the Company of the reasonably incurred survey costs in the 2007 Unbundled Rate Implementation Cost Deferral

Account on the understanding that the Company will seek to have all reasonably incurred costs recovered from large volume customers.

In order to allow customers to take advantage of the new Rate 300 and Rate 315, customers will have the opportunity to migrate to Rate 300 and 315 at all times during the Test Year until the point in time when 20 customers have migrated to the rate 300 series rates. Subject to the conditions of the Company's Early Termination Policy, the Company will permit migrating customers to terminate their bundled rate contracts early, on the understanding that customers will true up any imbalances in their existing contracts as per the provisions of the Company's Early Termination Policy.

If the survey results indicate that significantly more than 20 customers are prepared to commit to migrate, then the Company will undertake to develop an automated solution. If a smaller number of customers are prepared to commit to migrate, then the Company will conduct an analysis comparing the incremental cost of supporting incremental customers' activities and transactions using the manual solution versus the costs of an automated solution. The goal of the analysis will be to determine if it is feasible to expand the manual solution (and at what cost) versus the cost of an automated solution. Should an automated solution be required, the parties agree that the Company record associated costs in the Unbundled Rate Implementation Cost Deferral Account as per the NGEIR Settlement Proposal EB-2005-0551, Ex. S-1-1, p. 33.

If a manual solution permits more than 20 customers to migrate during the Test Year, any such additional spots will be implemented in a manner that is consistent with section 4(g) of the Settlement Agreement in EB-2005-0551 whereby 50% of the additional spots will be allocated to interested customers who will benefit the most from the service from a distribution rate perspective, and 50% of the additional spots will be allocated to interested customers entitled to subscribe for the service on the basis of a lottery system.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue except VECC which takes no position and did not participate in discussion on the issues discussed after the second paragraph above.

Evidence: The evidence in relation to this issue includes the following:

I-19-1 to 3	TransAlta Interrogatories 1 to 3
I-1-78 to 79	Board Staff Interrogatories 78 to 79
I-12-5 to 6	OAPPA Interrogatories 5 to 6

I-20-1	TransCanada Interrogatory 1

8.2 What are the actions or decisions necessary for the Board to be assured that the Board's decisions, including settlements, in the DSM (EB-2006-0021) proceeding will be appropriately captured and reflected in this proceeding?

(Complete Settlement)

There is an agreement to settle this issue as follows:

All parties agree that the implications of the Board's decisions in the DSM (EB-2006-0021) proceeding have been captured in the Company's filing in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

I-1-80 to 81	Board Staff Interrogatories 80 to 81
I-9-21 to 22	IGUA Interrogatories 21 to 22
I-24-76	VECC Interrogatory 76

9 RATE IMPLEMENTATION

9.1 How should the Board deal with any revenue deficiency applicable from January 1, 2007 to the date that the Board's decision is implemented?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as part of the package, as follows:

Parties agree that the Company can adjust rates to recover an additional $26.0 million, effective as of January 1, 2007, and that this will be implemented at the same time as the Company's April 1, 2007 QRAM is implemented. Parties agree with and support the Company's proposal to recover the full $26.0 million through (i) increased annualized rates for the remainder of the Test Year; and (ii) the use of a rate rider over the nine remaining months of the Test Year to recover the remaining balance of the $26.0 million. Intervenors agree that no issue or objection will be raised around whether any part of this $26.0 million is unrecoverable because it relates to the time period between January 1, 2007 and April 1, 2007.

There is no agreement as to whether or how the Company can recover any revenue deficiency in excess of $26.0 million.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OAPPA, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties except Schools accept and agree with the proposed settlement of aspects of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-2-1	Application
I-1-82	Board Staff Interrogatory 82
I-16-62 to 53	SEC Interrogatories 62 to 63

9.2 Should the Board set interim rates, effective January 1, 2007, to allow Enbridge to begin to recover its prospective revenue deficiency?

(Complete Settlement)

There is an agreement to settle this issue as follows:

This issue is no longer relevant, since the January 1, 2007 date has passed.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Direct Energy, GEC, HVAC, OESLP, Pollution Probe, Superior, TransCanada, TransAlta, Union Gas, Union Energy.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-2-1	Application
I-1-83 to 84	Board Staff Interrogatories 83 to 84
I-16-64 to 65	SEC Interrogatories 64 to 65

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at December 31, 2006 Principal ($000's)	Col. 2 Actual at December 31, 2006 Interest ($000's)	Col. 3 Accounts Agreed to be cleared with Final Rate Order Actual Balances at December 31, 2006 Principal ($000's)	Col. 4 Accounts Agreed to be cleared with Final Rate Order Actual Balances at December 31, 2006 Interest ($000's)	
	Non Commodity Related Accounts for One Time Rate Clearance						
1.	Demand Side Management Account	2006 DSMVA	374.7	(39.4)	-	-	
2.	Demand Side Management Account	2005 DSMVA	697.5	(9.7)	-	-	
3.	Demand Side Management Account	2004 DSMVA	2,013.9	149.1	2,013.9	149.1	
4.	Lost Revenue Adjustment Mechanism	2006 LRAM	-	-	-	-	
5.	Lost Revenue Adjustment Mechanism	2005 LRAM	-	-	-	-	
6.	Lost Revenue Adjustment Mechanism	2004 LRAM	(587.9)	13.6	(587.9)	13.6	
7.	Shared Savings Mechanism	2006 SSMVA	-	-	-	-	
8.	Shared Savings Mechanism	2005 SSMVA	-	-	-	-	
9.	Shared Savings Mechanism	2004 SSMVA	-	-	-	-	
10.	Class Action Suit D/A	2006 CASDA	23,514.2	117.1	-	-	
11.	Deferred Rebate Account	2006 DRA	(1,904.7)	(103.5)	(1,904.7)	(103.5)	
12.	Debt Redemption D/A	2006 DRDA	-	-	-	-	
13.	Ontario Hearing Costs V/A	2006 OHCVA	(612.8)	-	(612.8)	-	
14.	Manufactured Gas Plant D/A	2006 MGPDA	39.0	0.7	-	-	
15.	Electric Program Earnings Sharing D/A	2006 EPESDA	(175.1)	-	-	-	
16.	Corporate Cost Allocation	2006 CCAMDA	623.7	0.6	-	-	
17.	Unbundled Rate Implementation Cost D/A	2006 URICDA	480.5	-	-	-	
18.	Alliance/Vector Appeal Costs D/A	2006 AVACDA	529.2	17.3	-	-	
19.	Total Non Commodity Related Accounts for One Time Rate Clearance		24,992.2	145.8	(1,091.5)	59.2	
	Commodity Related Accounts for One Time Rate Clearance						
20.	2006 Purchased Gas V/A	2006 PGVA	(125,122.4)	(2,237.9)	-	-	a)
21.	2006 Transactional Services D/A	2006 TSDA	(7,508.8)	(15.5)	(7,508.8)	(15.5)	
22.	2006 Unaccounted for Gas V/A	2006 UAFVA	(11,739.1)	-	(11,739.1)	-	
23.	2006 Union Gas D/A	2006 UGDA	(2,919.3)	49.8	(2,919.3)	49.8	
24.	Total Commodity Related Accounts for One Time Rate Clearance		(147,289.6)	(2,203.6)	(22,167.2)	34.3	
25.	Total Deferral and Variance Accounts for One Time Rate Clearance		(122,297.4)	(2,057.8)	(23,258.7)	93.5	
	Non Commodity Related Accounts for Rate Base and Ongoing Rates Treatment						
26.	Gas Distribution Access Rule Costs D/A	2006 GDARCDA	7,923.3	62.1	-	-	b)
27.	Gas Distribution Access Rule Costs D/A	2005 GDARCDA	406.0	29.2	-	-	b)
28.	Gas Supply Risk Management Program D/A	2006 GSRMPDA	691.5	-	-	-	b)
29.	Total Deferral and Variance Accounts for Rate Base and Ongoing Rates Treatment		9,020.8	91.3	-	-	

Note: a) PGVA and related adjustments to be handled as part of April 2007 QRAM.

Note: b) These accounts would be required to be closed into rate base, with associated revenue requirement impacts, pending the hearing review and any eventual Board Approval.

EGD 2007 ADR PROPOSAL
BASED ON REVENUE DEFICIENCY OF $26 MILLION
FINAL

	Impacts Relative to July 1, 2006 T-service Rates					Impact Relative to January 1, 2007 T-service Rates	
Rate Class	Revenue to Cost Ratios 2007	Revenue to Cost Ratios 2006	Over/Under Contribution 2007	Over/Under Contribution 2006	Average Rate Impact T-Service	Average Rate Impact T-Service	TCPL Phase In Contribution
			$/M	$/M			$/M
1	1.01	1.01	10.35	8.75	2.07%	2.08%	5.01
6	1.01	1.01	5.06	4.19	0.66%	0.67%	4.89
9	0.69	0.69	-0.47	-0.59	6.44%	6.45%	0.00
100	0.97	0.98	-3.48	-2.92	1.91%	1.92%	0.00
110	1.01	1.01	0.38	0.33	-0.85%	-0.84%	0.00
115	0.90	0.90	-4.18	-5.49	0.96%	0.97%	-5.97
135	0.87	0.87	-0.28	-0.33	1.25%	1.25%	-0.60
145	0.97	1.03	-0.49	0.42	1.62%	1.63%	0.00
170	0.81	0.89	-4.98	-3.48	1.76%	1.76%	-3.20
200	0.98	0.98	-0.22	-0.20	4.60%	4.60%	0.00

Note: 2006 and 2007 Over/Under Contributions need to be adjusted by the TCPL phase in contribution amount to reflect the post October 1, 2007 situation.

EGD 2007 ADR PROPOSAL
BASED ON REVENUE DEFICIENCY OF $82.1 MILLION

Rate Class	Revenue to Cost Ratios 2007	Revenue to Cost Ratios 2006	Over/Under Contribution 2007	Over/Under Contribution 2006	Average Rate Impact T-Service	TCPL Phase In Contribution
			$/M	$/M		$/M
1	1.01	1.01	9.35	8.75	6.28%	5.01
6	1.01	1.01	5.42	4.19	4.52%	4.89
9	0.70	0.69	-0.48	-0.59	13.19%	0.00
100	0.98	0.98	-2.98	-2.92	5.48%	0.00
110	1.01	1.01	0.43	0.33	1.04%	0.00
115	0.90	0.90	-4.18	-5.49	1.96%	-5.97
135	0.87	0.87	-0.28	-0.33	2.54%	-0.60
145	0.97	1.03	-0.48	0.42	4.08%	0.00
170	0.82	0.89	-4.82	-3.48	4.24%	-3.20
	0.00		0.00			
200	0.98	0.98	-0.16	-0.20	7.70%	0.00

Note: 2006 and 2007 Over/Under Contributions need to be adjusted by the TCPL phase in contribution amount to reflect the post October 1, 2007 situation.

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 7.5

The issues related to Issue 7.5 ("Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?") have been the subject of the ongoing Open Bill Consultative. Parties have been able to come to an agreement to settle aspects of this issue.

This incomplete settlement, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this incomplete settlement will supersede the reference at page 43 of 47 of the January 29th Settlement Proposal which states that there is no settlement of Issue 7.5.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th Settlement Proposal apply to this Supplementary Settlement Proposal, except for (i) the chart of settled issues, which does not reflect this incomplete settlement of Issue 7.5; and (ii) any references to revenue deficiency and rate impact of the settlement, which would have to be changed to reflect the incremental financial impact of this Supplementary Settlement Proposal.

With that preamble, the following section represents the incomplete settlement that has been agreed upon.

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(Incomplete Settlement)

There is an agreement to settle aspects of this issue, as follows:

The parties agree to settle the third party billing component ("Billing Services") of Issue 7.5 Open Bill Access on the basis that the Company can proceed with the Billing Services on the following terms:

1. ***Compliance with Board Directive.*** All parties accept the Company's decision to respond to the Board's directive in EB-2005-0001 in two stages: an interim solution, using the Company's existing CIS, and a comprehensive solution, using the Company's planned new CIS. This settlement constitutes the interim solution until otherwise ordered by the Board in the Board review referred to in #2 below. Subject to the

presentation to the Board of the comprehensive solution, discussed in #2 below, all parties agree that this settlement constitutes an appropriate response to the Board's directive.

2. ***Comprehensive Solution.*** The Company agrees that it will file an application to the Board prior to the end of 2008 proposing the comprehensive Billing Services offering. Such application should include: a) a detailed report on the experience with the interim solution, b) any available consultants' reports with respect to costing and/or market pricing, c) the results of any customer communications activities and any customer or industry surveys, d) minutes and/or reports of the activities of the stakeholder committee referred to in #8 below, and e) the Company's proposal on whether the Billing Services should continue, and if so on what terms. Without limiting the generality of the foregoing, the Company's proposal may include changes to pricing, costing, shareholder incentive, and any other aspects of the Billing Services. In the event that in the Company's application the Company or any party proposes that the Billing Services should not continue, that party must also propose a reasonable transition period to reflect the time required for anyone using the Billing Services to shift to alternate billing arrangements. Nothing in this settlement implies that any party admits to either the relevance or the appropriate weight to be given to any particular evidence in this subsequent application, and all parties will be free to argue as they see fit with respect to any proposed evidence.

3. ***Pricing.*** During the interim period, but at least until December 31, 2008 parties accept the prices proposed by the Company, $0.829 for shared bills and $1.389 for standalone bills. All participants using the Billing Services will pay the same prices for the same services. The parties agree that prices for the Billing Services and any changes from time to time to the rules relating to the OBSDA referred to in #4 below must be approved by the Board.

4. ***Startup Costs.*** The shareholder will bear the startup and bill re-design costs associated with the Billing Services but will be allowed to recover 4 cents/bill from the Open Bill Service Deferral Account (OBSDA) over a two year period until the costs are recovered. The shareholder will not bear the costs associated with adding the Billing Services to the new CIS. The latter costs will be included in the costs of the Billing Services and recovered in revenues from the service.

5. ***Ratepayer Benefit.*** Subject to the shareholder incentive, set forth below, all net benefits, whether through mitigation of common costs, or net profits from the OBA services, will accrue to the benefit of the ratepayers. The Company agrees to include in its 2007 revenue requirement a net benefit of the service of $5.389 million. This number is derived from calculations /u found in JT.5, as updated to reflect this settlement. To be sure, all parties also agree If the net benefit of the service is greater or less than the amount included in rates, the difference will be credited or debited, as the case may be, to a new variance account, the Open Bill Access Variance Account (OBAVA) and refunded or charged to ratepayers in the following year. The net benefit shall be calculated as the total revenues from Billing Services, less

   a. the incremental costs to deliver those services;
   b. the amount referred to in #4 above; and,
   c. the shareholder incentive referred to in #6 below.

6. ***Shareholder Incentive.*** The Company will receive no incentive for Billing Services provided to any affiliate of the Company. For the Billing Services by any other person, the Company will be paid a commission as follows subject to an annual maximum calculated as 50% of the program's net margin:
   a. With respect to any bill on which Direct Energy (which for all purposes of these terms should be interpreted as including any successor to Direct Energy's water heater business) is the sole third party billing entity, $0.02 per bill;

   b. With respect to any bill on which there is any third party billing entity charge other than Direct Energy on the bill:

      i. $0.10 per bill in any month that the Billing Services service has only one active billing entity other than affiliates or Direct Energy;
      ii. $0.15 per bill in any month that the Billing Services service has two active billing entities other than affiliates or Direct Energy;
      iii. $0.20 per bill in any month that the Billing Services service has three active billing entities other than affiliates or Direct Energy;
      iv. $0.25 per bill in any month that the Billing Services service has more than three active billing entities other than affiliates or Direct Energy;

An entity will only be considered an "active billing entity" in any month in which it is billing products or services on at least 500 EGD bills.

7. ***Costing and Pricing Studies:*** The Company agrees that it will retain an independent consultant or consultants to undertake costing and pricing analyses for the Billing Services. The consultant's work will include assistance in determining a market price, and a review and analysis of the incremental and fully-allocated costs of these services. The Company will solicit the stakeholder group's input on the independent consultant(s), and statement of work for those consultant(s), but the Company will retain the right to make the final selection and define the terms of the reference. The cost of these studies will be included in the OBSDA.

8. ***Stakeholder Input.*** The Company will establish a stakeholder committee that includes users of the Billing Services, as well as ratepayer and industry representatives, to review the rules associated with participation in Billing Services. All parties to the agreement will be invited to become members of the stakeholder committee. The committee will meet from time to time as required to consider changes to the rules. Any changes to the rules that materially change the nature of the service will be reviewed by the stakeholder committee and reported to the Board to determine if their approval is required. The stakeholder committee will also be solicited for input into the Company's proposed communications plan, and other issues as they arise.

9. ***Affiliate Participation.*** Affiliates of the Company (including for the purpose of this settlement related parties such as limited partnerships or trusts that are not technically affiliates) may use the Billing Services on the same terms as any other third party biller. However, all parties agree with the principle that the Billing Services should be implemented in a manner that avoids ratepayer and/or consumer confusion, and, to the extent possible, prevents any participant from gaining any unfair market advantage by reason of their association with the utility, if any. The Company agrees that during the interim period it will implement such measures as may be necessary to achieve this principle, including but not limited to including in the Billing Services and enforcing in a commercially reasonable manner the following service rules::

    (a) No person, whether affiliate or otherwise, may use or associate itself with any name or logo on the bill that is the same as, similar to, or confusing with any name or logo that is associated with the Company (e.g. the "Enbridge" name and swirl logo).

(b) No person may use the Billing Services in an abusive or unfair manner in that it deliberately creates the impression that it has a preferred position relative to other market participants because of its relationship with the utility.

Notwithstanding, these restrictions in no way shape or form creates any future precedent to rely upon regarding the use of the Enbridge name or logo.

The parties acknowledge their mutual intention to bring issues with respect to affiliate participation to the stakeholder committee for resolution, but this statement will not limit any rights any party may have, whether under the Affiliate Relationships Code or otherwise, to have disputes resolved in any forum.

10. ***EnergyLink™ Relevance.*** If the Board in this proceeding approves the EnergyLink™ program proposed by the Company, the parties agree that whether a company is an EnergyLink™ participant or not will not affect whether that company can use the Billing Services, nor the rules or conditions under which they use the service.

11. ***Information.*** The Company will develop with input from the stakeholder committee an appropriate customer communication plan specific to Billing Services The Company shall provide to the Board and make available to all parties to this settlement agreement a report that includes revenues from Billing Services, and the costs of the services on a fully-allocated basis,an incremental basis and in a manner when known that is consistent with the methodology recommended in the study noted in paragraph 7, to the extent that this is different .

12. ***Logos and Bill Messaging.*** Logos and bill messaging will be provided to all participants in the Billing Services at no charge to facilitate entry of new users and help consumers differentiate the various parties with amounts billed on the EGD bill. Any provision of logos and bill messaging for the Billing Services will apply in the same manner to commodity vendors using the ABC Services for a reasonable charge, but commodity messaging will not be allowed unless EGD or one of its affiliates starts to market system gas.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Energy Probe, IGUA, OAPPA, Superior, TransAlta, TransCanada and Union Gas,

Approval: All participating parties accept and agree with the proposed settlement of this issue except that GEC and Pollution Probe reserve the right to pursue in the Hearing whether the Board should order that third parties not be allowed to use the Billing Services for the billing of specific products on the basis of their environmental attributes.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007
D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006

D1-11-19	Presentation – November 30th, 2006
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D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
D1-11-29	Third Party Access to the Bill Customer Communication Plan
D1-11-30	Billing Insert Customer Communication Plan
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
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I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5
I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference
JT1-JT22	Undertakings from January 10, 2007 Technical Conference

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 7.5

The issues related to Issue 7.5 ("Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?") have been the subject of the ongoing Open Bill Consultative. Parties have been able to come to an agreement to settle aspects of this issue.

This incomplete settlement, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this incomplete settlement will supersede the reference at page 43 of 47 of the January 29th Settlement Proposal which states that there is no settlement of Issue 7.5.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th Settlement Proposal apply to this Supplementary Settlement Proposal, except for (i) the chart of settled issues, which does not reflect this incomplete settlement of Issue 7.5; and (ii) any references to revenue deficiency and rate impact of the settlement, which would have to be changed to reflect the incremental financial impact of this Supplementary Settlement Proposal.

With that preamble, the following section represents the incomplete settlement that has been agreed upon.

7.5 Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

(Incomplete Settlement)

There is an agreement of some parties to settle aspects of this issue, as follows:

Proposed Billing Insert Settlement

The parties agree to settle the billing insert ("Insert Service") component of Issue 7.5 Open Bill Access on the basis that the Company can proceed with the Insert Service on the following terms:

1. ***Compliance with Board Directive.*** All parties accept the Company's decision to respond to the Board's directive in EB-2005-0001 in two stages: an interim solution, using the Company's existing CIS, and a comprehensive solution, using the Company's planned new CIS. This settlement constitutes

the interim solution until otherwise ordered by the Board in the Board review referred to in #2 below. Subject to the presentation to the Board of the comprehensive solution, discussed in #2 below, all parties agree that this settlement constitutes an appropriate response to the Board's directive as it pertains to bill inserts.

2. ***Comprehensive Solution.*** The Company agrees that it will file an application to the Board prior to the end of 2008 proposing the comprehensive Billing Insert Service offering. Such application should include: a) a detailed report on the experience with the interim solution, b) any available consultants' reports with respect to costing and/or market pricing, c) the results of any customer communications activities and any customer or industry surveys, d) minutes and/or reports of the activities of the stakeholder committee referred to in #8 below, and e) the Company's proposal on whether the Insert Service should continue, and if so on what terms. Without limiting the generality of the foregoing, the Company's proposal may include changes to pricing, costing, shareholder incentive, and any other aspects of the Insert Service. Nothing in this settlement implies that any party admits to either the relevance or the appropriate weight to be given to any particular evidence in this subsequent application, and all parties will be free to argue as they see fit with respect to any proposed evidence.

3. ***Pricing.*** For the interim period of 2007 and 2008, the Company agrees to reduce the minimum bids for bill inserts by one cent resulting in an average insert charge of 4 cents. For greater clarity, there shall be no right of first refusal for parties using the Company's Insert Service. The parties agree that prices for the Insert Service, and any changes thereto from time to time, must be approved by the Board.

4. ***Costing and Pricing. T***he Company agrees that it will retain an independent consultant to undertake a costing and pricing analysis for the Bill Insert Service for the comprehensive period. The consultant's work will include assistance in determining a market price, and a review and analysis of the incremental and fully-allocated costs of these services for the new CIS. The Company will solicit the stakeholder group's input on the independent consultant, and statement of work for that consultant, but the Company will retain the right to make the final selection and define the terms of the reference. The cost of this study will be included in the Open Bill Service Deferral Account (OBSDA).

5. ***Startup Costs.*** The shareholder will record the startup costs associated with the Insert Service in 2007 in the OBSDA. The startup costs associated with

adding the Insert Service to the new CIS will be included in the costs of the Insert Service and recovered in revenues from the service.

6. ***Ratepayer Benefit.*** The Company agrees to record the costs and revenues from the Insert Service in 2007 in the OBSDA and that the net proceeds will be shared 50/50. The parties agree that the shareholder incentive mechanism for Insert Service may need to be revised after the interim period and after the cost/price review to be consistent with the Board's rules for natural gas incentive regulation.

7. ***Inserts.*** Bill inserts would be allowed as proposed by EGD but revised to limit the number of external inserts to five (5) when safety inserts are scheduled. In all months, two inserts would be reserved for parties wishing to purchase bill inserts in a limited geographic area based on price per insert bidding.

8. ***Stakeholder Input.*** The Company will establish a stakeholder committee that includes users of the Insert Service, as well as ratepayer and industry representatives, to review the rules associated with participation in the Insert Services. All parties to the agreement will be invited to become members of the stakeholder committee. The committee will meet from time to time as required to consider changes to the rules. Any changes to the rules that materially change the nature of the service will be reviewed by the stakeholder committee and reported to the Board to determine if their approval is required. The stakeholder committee will also be solicited for input into the Company's proposed communications plans, and other issues as they arise. To ensure that consumer interests are being addressed, EGD will conduct focus groups and customer surveys on inserts as soon as possible in 2007 and report the findings to the stakeholder committee to determine if remedial action is required. EGD will also prescreen insert users and review the content of their bill inserts to ensure proper use of its billing envelope.

9. ***Problem Resolution.*** If the revised bidding and allocation processes restrict access in three consecutive months or the number of customer complaints on inserts increases significantly in the first two months of operation, the stakeholder committee would be convened to address the concern(s), and if the problem cannot be resolved within two (2) additional months that aspect of the Insert Service would be discontinued until the problem is addressed.

10. ***Affiliate Participation.*** Affiliates of the Company (including for the purpose of this settlement related parties such as limited partnerships or trusts that are

not technically affiliates) may use the Insert Service on the same terms as any other third party biller. However, all parties agree with the principle that the Insert Service should be implemented in a manner that avoids ratepayer and/or consumer confusion, and, to the extent possible, prevents any participant from gaining any unfair market advantage by reason of their association with the utility, if any. The Company agrees that during the interim period it will implement such measures as may be necessary to achieve this principle, including but not limited to including in the Insert Services and enforcing in a commercially reasonable manner the following service rules::

(a) No person, whether affiliate or otherwise, may use or associate itself with any name or logo in the billing envelope that is the same as, similar to, or confusing with any name or logo that is associated with the Company (e.g. the "Enbridge" name and swirl logo).

(b) No person may use the Insert Service in an abusive or unfair manner in that it deliberately creates the impression that it has a preferred position relative to other market participants because of its relationship with the utility.

Notwithstanding, these restrictions in no way shape or form creates any future precedent to rely upon regarding the use of the Enbridge name or logo.

The parties acknowledge their mutual intention to bring issues with respect to affiliate participation to the stakeholder committee for resolution, but this statement will not limit any rights any party may have, whether under the Affiliate Relationships Code or otherwise, to have disputes resolved in any forum.

11. ***EnergyLink^{TM} Relevance.*** If the Board in this proceeding approves the EnergyLink^{TM} program proposed by the Company, the parties agree that whether a company is an EnergyLink^{TM} participant or not will not affect whether that company can use the Insert Service, nor the rules or conditions under which they use the service, subject to the restriction on use of the Enbridge name and logo as described in Item 10 above.

12. This agreement should not be construed as a settlement of any aspect of issue 3.4, including but not limited to, arguments to restrict the Company's ability to promote EnergyLink^{TM} by bill insert or otherwise. Notwithstanding, the Company agrees to provide a schedule of EnergyLink^{TM} inserts on an annual basis, as part of the Binding Request for Bids process.

13. ***Commodity Marketing.*** Commodity bill inserts and marketing will not be allowed in the billing envelope unless EGD or one of its affiliates receives OEB approval to promote and/or market system gas commodity, in which case retailers, marketers and vendors will be allowed to promote and/or market their commodity offers through the Insert Service.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Energy Probe, IGUA, OAPPA, TransAlta, TransCanada and Union Gas,

Approval: Enbridge Gas Distribution, Direct Energy, OESLP and Union Energy accept and agree with this proposed settlement. HVAC, VECC and Schools do not agree with the proposed settlement. CCC opposes the proposed settlement in order that it may be permitted to pursue cross-examination on the issue. GEC and Pollution Probe reserve the right to pursue in the Hearing whether the Board should order that third parties not be allowed to use the Billing Services for the billing of specific products on the basis of their environmental attributes. Superior opposes the proposed settlement on the principle that it is not supportive of a settlement position that would allow for the Company to promote system gas through billing inserts as contemplated in Paragraph 13.

Evidence: The evidence in relation to this issue includes the following:

D1-11-1	Open Bill Access
D1-11-2	Statement of Principles, Objectives and Operating Arrangements for the Consultation Process for Enbridge Gas Distribution's Open Bill Access Proposal
D1-11-3	Open Bill Access Consultative Process
D1-11-4	Meeting Minutes
D1-11-5	Third Party Access Report
D1-11-6	Open Bill Access Update
D1-11-7	Summary Notes from Consultative Meeting on Wednesday July 26, 2006
D1-11-8	Open Bull Access Update – July 26th, 2006
D1-11-9	Summary Notes from Consultative Meeting on Tuesday November 14th, 2006
D1-11-10	Presentation – Consultative Meeting on Tuesday November 14th, 2006
D1-11-11	Open Bill Access Standard Bill Service Consultative November 14th, 2006
D1-11-12	Bill Insert Agreement
D1-11-13	Open Bill Standard Bill Service Description – Meeting November 14th, 2006 – Additional Request for Information
D1-11-14	Bill Inserts
D1-11-15	Bill Insert Agreement Draft
D1-11-16	Initial Draft for Discussion Binding request for Bids – Third Party Bill Inserts for 2007

D1-11-17	Presentation – Consultative Meeting on November 23rd, 2006
D1-11-18	Open Bill Access – Summary Notes from Consultative Meeting on November 23rd, 2006
D1-11-19	Presentation – November 30th, 2006
D1-11-20	Criteria for Bill Inserts
D1-11-21	Open Bill Access – Summary Notes from Conference Call between EGD, Intervenors, and Consultants on Friday, December 1st, 2006
D1-11-22	Shared Bill Benefit Calculation
D1-11-23	Presentation – December 5th, 2006 Corrected Forecast
D1-11-24	Bill Inserts
D1-11-25	Bill Inserts
D1-11-26	Bill Inserts
D1-11-27	Request for Binding Bids – 2007 Third Party Bill Insert Service
D1-11-28	Binding Service Request and Bid Form – 2007 Third Party Bill Insert Service
D1-11-29	Third Party Access to the Bill Customer Communication Plan
D1-11-30	Billing Insert Customer Communication Plan
I-1-74 to 77	Board Staff Interrogatories 74 to 77
I-2-52	CCC Interrogatory 52
I-4-1 to 12	Direct Energy Interrogatories 1 to 12
I-16-60 to 61	SEC Interrogatories 60 to 61
I-18-1 to 5	Superior Interrogatories 1 to 5
I-22-1 to 5	Union Energy Interrogatories 1 to 5
I-24-74 to 75	VECC Interrogatories 74 to 75
I-26-12 to 20	HVAC Interrogatories 12 to 20
L-4-1	Evidence of Direct Energy
L-22-1	Evidence of Union Energy
L-26-1	Evidence of HVAC
I-27-1 to 35	Enbridge Gas Distribution Interrogatories of Union Energy 1 to 35
I-29-1 to 5	Enbridge Gas Distribution Interrogatories of Direct Energy 1 to 5
I-30-22 to 24	Enbridge Gas Distribution Interrogatories of HVAC 22 to 24
I-32-1 to 5	HVAC Interrogatories of Direct Energy 1 to 5
I-33-1 to 12	Superior Energy Management Interrogatories 1 to 12
I-34-1 to 21	Union Energy Interrogatories of Direct Energy 1 to 21
I-35-1 to 11	Direct Energy Interrogatories of Union Energy 1 to 11
I-36-1 to 16	Direct Energy Interrogatories of HVAC 1 to 16
	Transcript of January 10, 2007 Technical Conference
JT1-JT22	Undertakings from January 10, 2007 Technical Conference

SUPPLEMENTARY SETTLEMENT PROPOSAL : ISSUE 6.3

The Settlement Proposal filed as Exhibit N1, Tab 1, Schedule 1, which was approved by the Board on January 29, 2007 (the "January 29th, 2007 Settlement Proposal"), notes at page 39 of 47 that Issue 6.3 was an Incomplete Settlement. Specifically, there was no agreement on the Company's proposed Invoice Vendor Adjustment (IVA) charge. Discussions have continued in respect of the IVA charge and Parties have been able to come to an agreement to settle outstanding issues relating to the IVA charge.

If this Supplementary Settlement Proposal for the IVA charge is approved by the Board, it will be added to the January 29th, 2007 Settlement Proposal, and the provisions of this Supplementary Settlement Proposal will supersede the reference at page 39 of 47 of the January 29th, 2007 Settlement Proposal which states that there is No Settlement in respect of the IVA charge.

Parties agree that the provisions of the Introduction and Overview sections of the January 29th, 2007 Settlement Proposal apply to this Supplementary Settlement Proposal, except for the chart of settled issues, which does not reflect the complete settlement of Issue 6.3.

With this preamble, the following section represents the complete settlement that has been agreed upon.

6.3 Should the Board approve the contents of the Applicant's Rate Handbook?

(Complete Settlement)

There is an agreement to settle aspects of this issue, as follows:

The parties agree that:

1. The IVA charge by the Company will equal 0.65% of the absolute dollar value of the adjustment. Parties agree that this IVA charge is an interim measure that will apply from June 1, 2007 to December 31, 2007, and is without prejudice to any Party proposing an alternative IVA charge commencing January 1, 2008.

2. The Company will consult with interested parties and will consider the merits of bringing forward a different fee structure for a cost-based IVA charge. The Company will seek approval from the OEB for the new IVA charge, to be effective January 1, 2008.

3. Parties agree that the IVA charge is designed to only recover the costs incurred by the Company to provide this service. As a result, Parties agree that there is no need to adjust the revenue deficiency as a result of forecast IVA charge revenues and costs. The Company will provide parties with a summary of 2007 IVA charge revenues and costs subsequent to December 31, 2007.

***Participating Parties*:** All parties participated in the negotiation and settlement of this issue except Energy Probe, GEC, HVAC, LIEN, OAPPA, Pollution Probe, SEC, Superior, TransCanada, TransAlta, Union Energy and Union Gas.

Approval: All participating parties accept and agree with the proposed settlement of aspects of this issue. Without limiting the generality of the Introduction to the Settlement Proposal, VECC's acceptance of this proposed settlement is without prejudice to it proposing that IVA charges be reviewed as part of the Board's generic review of the QRAM/System Gas. CCC, HVAC, IGUA, Energy Probe, SEC, and Union Energy take no position.

Evidence: The evidence in relation to this issue includes the following:

D1-10-2, plus attachment	Gas Distribution Access Rule
Tr. 5, pp. 68, 73-74	

SETTLEMENT PROPOSAL FOR CUSTOMER CARE AND CUSTOMER INFORMATION SYSTEM ("CIS") ISSUES

I. PREAMBLE

The following issues related to Enbridge Gas Distribution's Customer Care O&M and Customer Information System ("CIS") capital budgets, and related matters, have been among the subjects addressed as part of the ongoing Customer Care/CIS Consultative:

7.1 Has Enbridge complied with the direction, in the EB-2005-0001 Decision, to file in evidence the following Customer Care Support Cost information: all agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS; the Program Agreement between CWLP and Accenture, including any amendments or revisions; financial statements for ECSI and CWLP (historical, bridge and test year); the return analyses described in the decision? (D1-12-3)

7.2 What actions or decisions are required by the Board regarding items in the 2006 and 2007 capital budgets which might be duplicated in the upcoming application for a Regulatory Asset Account? (D1-10-1, p. 2/AppA)

7.3 Are the forecast costs of the new CIS system appropriate? (B1-5-1, p. 3)

7.4 What are the appropriate costs for CIS and Customer Care for 2007, including internal and transition costs? (D1-12-1, p. 2 and D3-2-1, p. 1)

As set out below, parties have been able to come to an agreement to settle these issues, as well as other matters related to Customer Care and CIS.

All aspects of this Supplementary Settlement Proposal are subject to approval by the Board. The parties to the settlement all agree that this Supplementary Settlement Proposal is a package: the individual aspects of this agreement are inextricably linked to one another and none of the parts of this settlement are severable. As such, there is no agreement among the parties to settle any aspect of the issues addressed in this Supplementary Settlement Proposal in isolation from the balance of the issues addressed herein. The parties agree, therefore, that in the event that the Board does not accept this Supplementary Settlement Proposal in its entirety, then (in accordance with the Board's Settlement Conference Guidelines) the Board will reject the

Supplementary Settlement Proposal in its entirety and proceed to hearing on all of the issues listed above.

This Supplementary Settlement Proposal, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this Supplementary Settlement Proposal will supersede the references at pages 41 and 42 of the January 29th Settlement Proposal which state that there is no settlement of Issues 7.1 to 7.4.

If approved by the Board, this Supplementary Settlement Proposal will reduce the Company's revenue deficiency for the Test Year by approximately $24.2 million, from the $52.1 million remaining as the revenue deficiency in the Company's Application, after the Settlement Proposal (Ex. N1-1-1) revenue deficiency of $29.9 million was approved by the Board on January 29, 2007 (with $26.0 million thereof recoverable in interim rates effective April 1, 2007). The remaining revenue deficiency at issue in the Company's Application is now about $26.1 million[1], taking into account the fact that parties are agreeing in this Supplementary Settlement Proposal that the Company can recover a revenue deficiency of approximately $1.8 million in respect of customer care and CIS costs in the Test Year.[2] This $1.8 million Customer Care revenue deficiency, which is described below in more detail, is the result of extra costs from customer growth, offset by a reduction in bad debt costs.

Finally, although it is not set out expressly in the sections that follow, the parties agree that, as part of this settlement package, Issue 7.2 is resolved because the Regulatory Asset Account application is no longer necessary. The parties also agree that, in response to Issue 7.1, the Company has filed those materials stipulated in the Board's EB-2005-0001 Decision that are currently available. There are, however, some agreements associated with the Company's move away from CustomerWorks Limited Partnership ("CWLP"), including transition agreements with Accenture Business Services for Utilities ("ABSU")[3], that are not completed. Accordingly, at this time Issue 7.1 is partially resolved and the parties expect that it will be completely resolved when those agreements are finalized and filed.

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1 Note that this does not include any impact of Supplementary Settlement Proposals related to bill access and IVA charges.

2 The $1.8 million deficiency to be recovered for Customer Care is derived by starting with the customer care deficiency of $26 million, set out at lines 2 and 3 of the Table at Ex. N1-2-2, p. 2, and then subtracting $24.2 million, which is the agreed-upon revenue deficiency reduction that would result from approval of this Supplementary Settlement Proposal.

3 For the purposes of this Supplementary Settlement Proposal, both Accenture Business Services for Utilities and Accenture Inc. will be referred to as "ABSU".

With that preamble, the following represents the settlement that has been agreed upon.

II INTRODUCTION

Beginning in 2000, Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company") entered into a series of arrangements whereby CIS and Customer Care services were acquired through a related company, Enbridge Commercial Services Inc. ("ECSI"). ECSI subsequently entered into a limited partnership arrangement with Terasen Inc., CWLP, for the purpose of providing customer related business support and information technology services to utilities. Enbridge Gas Distribution entered into a new Customer Care services agreement with CWLP and consented to ECSI's assignment of its CIS service agreement to CWLP, both effective from January 1, 2002. In August 2002, CWLP entered into an agreement in writing with ABSU, hereinafter referred to as the "Program Agreement", whereby CWLP transferred certain assets and all operating personnel to ABSU, and ABSU agreed to provide Customer Care services, including CIS hosting services, on behalf of CWLP to Enbridge Gas Distribution and other utilities for the period that could be as long as 2002 to 2011 (inclusive) for amounts detailed in a Schedule to the Program Agreement. Since 2002, pursuant to the Program Agreement, ABSU has been performing the Customer Care and CIS services for the Company on behalf of CWLP.

A portion of the fees which the Company has paid to CWLP/ECSI to acquire CIS and Customer Care services was paid by CWLP/ECSI, ultimately, to Enbridge Gas Distribution's parent or other affiliates.

In a series of rate cases, the Intervenors expressed their objection to these arrangements, arguing that ratepayers should only be required to pay for CIS and Customer Care services at a market price or, failing a competitive process, at the cost of any affiliate, or related company, providing the services, including an appropriate return on such an endeavour. In the 2006 rate case decision, the Board agreed that what ABSU was paid to provide the services to Enbridge Gas Distribution for Customer Care and CIS services was relevant to the determination of the market prices for the services. The Board ultimately used CWLP revenue from Enbridge Gas Distribution, expressed as a proportion of CWLP's total revenues, as a tool to derive CWLP overearnings attributable to Enbridge Gas Distribution, and then, using the utility allowed return, the Board determined the amount recoverable from Enbridge Gas Distribution's ratepayers. The Board, in decisions in rate cases beginning in 2003 and culminating in Enbridge Gas Distribution's 2006 rates case, urged the Company to obtain CIS and Customer Care services by direct competitive tender which, in the Board's view, should exclude the right of first refusal in favour of CWLP.

Following the Decision with Reasons of the Board in EB-2005-0001, Enbridge Gas Distribution undertook to do the following:

1. Acquire a new Customer Information System (CIS) through a direct competitive tender;

2. Acquire Customer Care services through a direct competitive tender.

Enbridge Gas Distribution also convened a consultative process (the "Consultative") through which Intervenors could monitor and comment on these procurement processes. In light of the concern which Intervenors had, in past rate cases, expressed about Enbridge Gas Distribution's arrangements for acquiring CIS and Customer Care Services, the Intervenors wanted to be assured that the procurement processes were consistent, in all respects, with accepted industry standards, and that the arrangements resulting from the procurement processes will not result in amounts being paid by Enbridge Gas Distribution to CWLP, Enbridge Gas Distribution's affiliates, or its parent. Enbridge Gas Distribution convened the Consultative in part to give the Intervenors those assurances. To further ensure that the Consultative could achieve its goals, Intervenors were given access to independent expertise to advise them on the procurement processes and the results therefrom.

Through the Consultative, the Company informed Intervenors that CWLP has not indicated any intention to exercise its right of first refusal in respect of the new Customer Care or CIS services. CWLP/ABSU have now committed to include a clause in the transition agreements associated with the move to new service providers that will waive CWLP's right of first refusal when the transition agreements are signed.

The Company represents that, apart from the payments to be made by the Company to CWLP up to April 1, 2007, no more than $8.34 million in aggregate will be paid by any person to CWLP, ECSI, EI or any other related entity in relation to any Customer Care or CIS services included within this agreement and provided to Enbridge Gas Distribution by any person during the course of this agreement.

As a result of the work of the Consultative, Enbridge Gas Distribution and the Intervenors have been able to reach agreement on certain aspects of the procurement processes completed to date. The work of the Consultative is described in the pre-filed evidence of Mario Bauer, filed as Exhibit L-2.

The procurement processes will not be completed, with the selection of a new CIS and a new Customer Care service provider, until mid 2007. As a result, the cost of the new CIS and of the new Customer Care service provider cannot be estimated at this time. In addition, the prudence and cost consequences of the CIS and Customer Care arrangements cannot be determined until those arrangements have been finalized, which is expected to be in the first half of 2007. As well, the new CIS will not become operational until June 2009 and it is only at that time that final costs for the new CIS will be known. Finally, the shortlisted bidders for Customer Care services include ABSU and a third party, so there is the potential that a new service provider, other than ABSU, will be selected. The introduction of a Customer Care service provider, other than ABSU, will involve transition arrangements with ABSU and others in both 2007 and 2008, and the costs consequences and upper limits of those costs have been estimated. Final estimates of such costs cannot be made until a later date.

Within these practical constraints, the parties have settled Issues 7.1 through 7.4, which are the Customer Care and CIS issues in this EB-2006-0034 proceeding. The settlement necessarily reflects the fact that certain aspects of the CIS and Customer Care arrangements, including the final costs and contract terms, will not be known until later in 2007.

The parties have agreed that a placeholder amount will be used to establish the revenue requirement for Customer Care costs for 2007. The placeholder chosen is the cost-per-customer set by the Board in the EB-2005-0001 Decision, at $49.58. As a result of this settlement, the total Customer Care budget to be recovered in rates for 2007, including all internal and external costs (except for bad debt), and including all revenue requirement impacts of CIS, will be $90.8 million, plus an amount of $15.1 million representing the provision for uncollectible accounts.

The settlement includes provision for a “true-up” process to adjust the revenue requirement to reflect the prudent and reasonable forecast amounts resulting from the procurement processes, and to reflect the agreed-upon recovery of certain “transition” costs.

The parties believe that a six-year term, covering the period 2007 through 2012 inclusive, is the appropriate term over which to calculate the revenue requirement relating to Customer Care and CIS. The expected costs of CIS and Customer Care during that period may fluctuate year over year. The parties agree that the annual amounts included in rates should be smoothed, over the 2007-2012 term, to avoid swings in rates. The effect of the true-up process is (a) to capture any variance between the 2007 placeholder for Customer Care and CIS revenue requirement of $90.8 million and the normalized revenue requirement for 2007 and pay that variance to, or recover it from, the ratepayers in the 2008-2012 period, and (b) establish the component of the Company’s revenue requirement relating to Customer Care and CIS (except bad debt) for the period 2007-2012, and smooth the rate impacts of that component over that period.

To reflect the settlement the parties have agreed upon a template (the “Template”), which sets out all of the relevant categories of expenses over the 2007 to 2012 period that relate to Customer Care and CIS (except for bad debt costs). The costs in a number of those categories can be established today, and the parties have therefore agreed to those amounts. However, some costs to be set out in the Template must be determined when the contract prices and other costs are known. For those costs, the parties have agreed to the parameters under which those costs will be calculated or forecast and then included in the true-up calculation.

As the parties anticipate the possibility of an incentive regulation ("IR") regime, the terms of which are expected to be established later in 2007, they believe that the true-up should occur at a time when the IR formula for the Company has been established. Once the contract for Customer Care services has been signed, and the terms of IR are known, which is expected to be in the fall of 2007, the parties have agreed that the true-up should take place, in accordance with the true-up rules set out in this Settlement Proposal and Appendix. Parties agree that adjustments may need to be made to aspects of this agreement in the event that the IR regime that, for the purposes of calculation, was assumed by the parties in creating the Template – ie. a price cap IR regime of five years in duration, beginning January 1, 2008 - is not established. Adjustments may need to be made to the normalization approach set out in the True-Up Rules (which are attached) to make it compatible with the IR model and formula that is approved for Enbridge Gas Distribution. Any such adjustments would not affect the total revenue requirement to be recovered over the term of this agreement, but they may impact upon the amount to be recovered in each year of the agreement under the normalization approach that is used.

Finally, the parties agree that the Consultative will continue to monitor the completion of the procurement process, up to and including reviewing the final terms of the contracts, and thereafter, the implementation of the CIS and Customer Care arrangements, which the parties agree will be no later than six months after the in-service date for the new CIS. As has been the case to date, the Intervenors involved in the Consultative agree that they will raise any concerns about the ongoing process, and the outcomes from that process, as soon as they have sufficient information to identify and communicate those concerns. If the Intervenors involved in the Consultative believe that they are not receiving sufficient information, they will advise the Company immediately. The parties agree that the Consultative will continue to work in a timely, responsive and reasonable manner until its mandate is completed. Finally, the parties agree that all costs of the Consultative, for as long as it continues, will be fully recoverable from ratepayers. Costs of the Consultative that are incurred in 2007 will be included in the already established 2007 Ontario Hearings Costs Variance Account (2007 OHCVA). Parties agree to support the continuation of appropriate deferral accounts in future years for the recording and disposition of future costs of the Consultative, unless these costs are included in the Company's regulatory O&M budget during the IR term.

II TERMS OF SETTLEMENT

Against that background, the parties have agreed as follows:

(A) 2007 O&M Customer Care costs

As noted above, certain of the anticipated costs associated with Customer Care during the period 2007 through 2012 will not be known until RFP processes currently being carried out by the Company are completed and market prices are identified. As a result, revenue requirement will be established for 2007 using a placeholder to calculate the Customer Care costs. The placeholder will be the Board-approved 2006 cost per customer of $49.58, times the projected number of customers in 2007, 1,831,283, to get a total Customer Care placeholder of $90.8 million for 2007.

The parties agree that projected bad debt costs (Provision for Uncollectible Accounts) of $15.1 million as filed by the Company shall be recoverable in rates in 2007. This agreement does not deal with bad debt costs beyond 2007; as a result, bad debt costs are not included in the True-Up calculation. For the period from 2008 to 2012, bad debt costs will be dealt with by the Board along with other O&M costs, separately from other Customer Care costs which are the subject of this agreement, in such other proceeding or proceedings as the Board may determine.

For the purposes of settlement, the Customer Care placeholder of $90.8 million plus bad debt costs of $15.1 million will replace the amounts in the Company's Application and pre-filed evidence which total $130.1 million, and are comprised of $101.6 million for Customer Care and CIS Service Charges, $3.4 million for Customer Care Internal Costs, $15.1 million for Provision for Uncollectibles and $10.0 million for transition costs (see Exhibit D1-2-1, p. 3, Table 1, lines 2 to 4 and Ex. D1-1-1, p. 1, Table 1, line 3). These internal and transition costs are addressed in the True-Up Rules which are attached as Appendix A.

As a result, the settlement of this item will reduce the Company's revenue deficiency for the Test Year by approximately $24.2 million, from the $52.1 million remaining as the revenue deficiency in the Company's Application, after the Settlement Proposal (Ex. N1-1-1) revenue deficiency of $29.9 million was approved by the Board on January 29, 2007 (with $26.0 million thereof recoverable in interim rates effective April 1, 2007). The remaining revenue deficiency at issue in the Company's Application is now about $26.1 million, taking into account the fact that parties are agreeing in this Supplementary Settlement Proposal that the Company can recover a revenue deficiency of approximately $1.8 million in respect of customer care and CIS costs in the Test Year (the amount that is the difference between the 2006 Board-approved budget of $104.1 million and the $105.9 million total amount for 2007 for Customer Care, CIS and bad debt costs). This $1.8 million Customer Care revenue deficiency can be derived by accounting for customer growth in F2007 over the previous year (the $49.58 placeholder is multiplied by 46,228, which is the forecast number of new customers in 2007) and adjusting for a reduction of $500,000 in bad debt costs, as compared to F2006.

(B) 2007 Capital costs related to CIS

The parties agree that any capital spending by the Company during the 2007 Test Year related to the new CIS shall be in addition to the Company's overall Board-approved capital budget of $300 million plus the costs of the Portlands Energy Centre LTC. This is consistent with the language in Issue 1.1 of the Settlement Proposal in this EB-2006-0034 proceeding, which was approved by the Board on January 29, 2007 and which stated that "[p]arties have reached a global settlement of all 2007 Rate Base issues, except for issues related to the capital budget for the new CIS system" (Ex. N1-1-1, p. 13). No capital expenditures in 2007 relating to the new CIS will be closed to rate base in 2007, and the new CIS will have no impact on 2007 rates.

(C) Selection process for new CIS and Customer Care service providers and Transition Plan

As explained above in the Introduction section, it is anticipated that the selection of a new CIS and a new Customer Care service provider will occur in the second quarter of 2007, when the associated RFP processes are completed.

Once selections are made, contracts will have to be negotiated and settled with the chosen parties. At that time, some of the expected costs of the new CIS, and payments to be made to the new Customer Care service provider, will be established between Enbridge Gas Distribution and the service providers through contractual arrangements. The Consultative will continue to function until the completion of the procurement process, the implementation of those CIS and Customer Care arrangements and the completion of the true-up process described below. The Consultative will be involved with monitoring the selection process and reviewing the terms and prudence of the resulting contracts, including the reasonableness of their costs. Parties agree that the Consultative will continue to work in a timely, responsive and reasonable manner until its mandate is completed.

The selection processes for both the CIS and the Customer Care services RFPs are underway. At this point, the remaining shortlisted bidders for the Customer Care services include ABSU and a third party. The remaining shortlisted bidders for the system integrator component of the new CIS include ABSU and a third party. The parties have agreed that for the time period from January 1, 2007 to March 31, 2007, CWLP will continue to provide CIS and Customer Care services to Enbridge Gas Distribution. For the period commencing April 1, 2007 and concluding no later than September 30, 2008, Enbridge Gas Distribution is making arrangements with ABSU to provide the CIS and Customer Care services directly to Enbridge Gas Distribution, at least until the potential transition to new service providers is complete.

There are two types of transition costs addressed in this Supplementary Settlement Proposal: CIS transition costs and Customer Care transition costs.

The parties acknowledge and agree that all transition costs with respect to the new CIS are included in the $118.7 million capital cost of the new CIS (discussed below), whether or not ABSU is awarded the system integrator component of that project.

The parties further acknowledge and agree that, in the event that ABSU is chosen as the Customer Care service provider, there will be no transition costs associated with Customer Care services. In the event that the third party is chosen as the Customer Care service provider, then there will be transition costs associated with the move to the new service provider. Enbridge Gas Distribution has prepared, and has shared with the Consultative, a Transition Plan that sets out how Customer Care may be transitioned to a new service provider. The parties agree that there will be costs associated with any such transition, and that those costs are recoverable in the manner and amounts described in detail in the True-Up Rules at Appendix A. The Company agrees that it will keep the transition costs, and the transition time period, to a reasonable level while managing the risks associated with transition and ensuring that the ongoing provision of Customer Care services meets OEB-mandated service levels. In this regard, the Company agrees that while the maximum time period for transition to a new Customer Care service provider will be 18 months from April 1, 2007, it will make best efforts to shorten that time period. The Company will ensure that its arrangements with ABSU will allow the Company to direct ABSU to cease the provision of some or all Customer Care transition services before the end of 18 months and, as a result, to reduce the transition costs payable by Enbridge Gas Distribution to ABSU.

(D) The True-Up process and Revenue Requirement for 2008 to 2012

(i) Overview

The parties agree that, on a date (the "True-Up Time") that is the later of (a) the date when the Company's Customer Care RFP is completed and the contract is signed, and

(b) the date when the Board's decision with respect to the duration, rules and formulae for IR that relate to Enbridge Gas Distribution is released, the parties will calculate a true-up and smoothing for the Customer Care amounts for 2007 to 2012, using the specific rules set forth in Appendix A to this Settlement Proposal (the "True-Up Rules").

As set out in more detail below in Appendix A, the amount of the Customer Care costs that are projected to be incurred by the Company during the 2007 to 2012 period, and which the Company will recover in rates, will be determined by the parties at the True-Up Time in accordance with the criteria specified in the True-Up Rules. The components of the Customer Care costs and revenue requirement are itemized in the "Customer Care and CIS Settlement Template" (already defined as the "Template"), which is attached to Appendix A.

It is the intention of the parties that the True-Up process will be used to determine the Customer Care amount for 2007 (the "Normalized 2007 Customer Care Revenue Requirement") that, when adjusted using the True-Up Rules for each year until 2012, will allow the Company to fully recover in rates the costs incurred in providing Customer Care services (including CIS) during the period from 2007 through 2012.

In the event that the parties are unable to agree on the amount of any component of the Normalized 2007 Customer Care Revenue Requirement or any number to be included in the Template, other than those numbers that are fixed by the terms of this agreement, then parties agree that the unresolved dispute will be determined by the Board in accordance with the criteria specified in the True-Up Rules. Specifically, if the parties have not agreed to the Normalized 2007 Customer Care Revenue Requirement within sixty days of the True-Up Time, they shall list the components of the calculation that are in dispute, and provide that list to the Board for determination in accordance with the criteria specified in the True-Up Rules.

The outcome of the True-Up process will be the subject of a separate application to the Board. That application will include, for Board approval, all numbers that are agreed upon and set in accordance with the True-Up Rules, as well as the list of the items remaining at issue to be determined by the Board.

(ii) 2007 Customer Care Variance Account

At True-Up Time, the Company will calculate the difference (the "2007 Customer Care Revenue Requirement Variance") between that amount of revenue requirement that is, pursuant to the True-Up Rules, recoverable for 2007 Customer Care costs (the Normalized 2007 Customer Care Revenue Requirement) and the placeholder of $90.8 million, and will credit or debit the 2007 Customer Care Revenue Requirement

Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012. The 2007 Customer Care Variance Account will be cleared in accordance with the True-Up Rules.

In order for effect to be given to this provision of this Settlement Proposal, parties agree that it is appropriate that a 2007 Customer Care Variance Account be created, and continued until 2012.

(iii) Revenue requirement for Customer Care costs between 2008 and 2012

The revenue requirement that the Company will be entitled to recover each year in respect of Customer Care costs (including CIS but not including bad debt) from 2008 to 2012 shall be the Normalized 2007 Customer Care Revenue Requirement, as adjusted for each year from 2008 to 2012 (inclusive) by the Incentive Regulation formula. The intention of the parties is that this will result in a relatively stable revenue requirement for CIS and Customer Care services over a five year period.

As set out above, and explained in the True-Up Rules, the "Normalized 2007 Customer Care Revenue Requirement" will be the amount that, when adjusted according to the True-Up Rules (including the rules for IR described as part of the True-Up Rules) for each year until 2012, will allow the Company to fully recover in rates the total of all forecast prudent and reasonable Customer Care costs (including CIS but not including bad debt) for the period from 2007 through 2012.

The parties agree that all O&M costs associated with Customer Care (except for bad debt costs), including O&M relating to the Company's proposed new CIS, are included in the calculation of Normalized 2007 Customer Care Revenue Requirement and therefore will be properly recovered in rates during the period 2007 through 2012 through the operation of the True-Up Rules.

The Company agrees that, once the outstanding items on the Template are determined, and completed, and, as a result, the Normalized 2007 Customer Care Revenue Requirement is established, the Company will not seek any adjustment to its rates or revenue requirement that is directly or indirectly based on changes in Customer Care costs during the term of this agreement. Intervenors similarly agree that they will not seek adjustments to the Company's rates or revenue requirement that is directly or indirectly based on changes in Customer Care costs. As expressed above, bad debt costs are not included as part of the Customer Care costs that are the subject of this agreement from 2008 to 2012.

Notwithstanding the limitations expressed in the preceding paragraph, the parties agree that in the event that new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period up to and including 2012, and those requirements materially change the level of Customer Care costs, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the agreement will be established at the IR proceeding. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the IR rules that apply to the Company.

In order to give effect to certain aspects of the True-Up Rules, as detailed in Appendix A, parties agree that it is appropriate that 2007 and 2008 Customer Care Transition Costs Variance Accounts be created to track certain transition costs related to Customer Care. The transition costs to be tracked in these accounts relate to activities that ABSU and external contractors and internal resources will undertake to transfer knowledge and services to the new service provider. This will include such tasks as training, documentation and management of the vendors through the transition. The transition costs to be tracked in these accounts are subject to a maximum total amount of $11.1 million. The details of the 2007 and 2008 Customer Care Transition Costs Variance Accounts are set out below, as part of the True-Up Rules.

(iv) New CIS

As the Board is aware, the Company is planning to replace its current CIS service with a new CIS that will be owned by the Company. When this system is implemented, which is expected in 2009, its capital cost will be included as part of the Company's utility rate base. Through the Consultative process, and subject to an adjustment described below, the parties have agreed that a reasonable cost for this asset is $118.7 million, including procurement costs of $5.1 million. The parties agree that rates will be set during the period of this agreement on the basis of a CIS cost that will be no higher than $118.7 million. This $118.7 million budget consists of an amount of $42 million for system integrator contract costs, which are subject to a direct competitive tender process, and an amount of about $76.7 million which the Company will manage and control during the CIS procurement and implementation process.

All parties agree that the Company's revenue requirement associated with Customer Care activities for the 2007 to 2012 period will incorporate a portion of the cost for the new CIS of $118.7 million, including procurement costs of $5.1 million, as set out below. The procurement process that provides support for the reasonableness of this cost is described in the evidence of Mario Bauer (Exhibit L-2), and the CIS cost analysis attached thereto. The parties agree that this $118.7 million cost is subject to reduction in the event that the system integrator contract costs arrived at through the CIS procurement process are less than $42 million. In the event that the system integrator costs are $42 million or more, then the parties agree to the cost of $118.7 million for the completion of the Template and the term of this agreement.

While the revenue requirement attributable to CIS shown in Row 3 of the Template is not yet finalized, the parties agree upon the following:

1. As stated above, the parties agree upon the prudence of the CIS procurement process and the capital cost for the new CIS of $118.7 million, which includes procurement costs of $5.1 million.

2. The parties agree that the amounts to be recovered in rates will be reduced, if the system integrator contract costs arrived at through the CIS procurement process are less than $42 million.

3. Subject to the restrictions on CIS costs set forth in this agreement, there is agreement that all prudently incurred and reasonable costs associated with the new CIS, including return and income taxes, should be recoverable in rates, during the term of this agreement, and for the 10-year economic life of the new CIS assets.

4. The parties agree that the term of this agreement will be six years from 2007 to 2012, in order to enable the smoothing and managing of the recovery of the revenue requirement attributable to the new CIS during those years.

5. The parties agree that they support the decision to procure the new CIS as prudent, the inclusion of the new CIS in rate base in 2009, and the recovery of all amounts associated with the new CIS subject to the terms of this agreement. Subject to any adjustment that may be made to rate base as of December 31, 2012 to reflect the actual costs of the new CIS, as set forth below, the parties agree that, as of January 1, 2013, the amount included in opening rate base for the new CIS shall be its 2012 closing net book value of approximately $71.4 million.

6. The parties agree that, for rate-making purposes, the in-service date of the new CIS will be deemed to be July 1, 2009, regardless of the actual in-service date, and the rate base for the new CIS will be calculated in all respects as if it was brought into service on July 1, 2009.

7. The parties agree that, for rate-making purposes, CIS Capital Costs at the end of the term of this Agreement will be treated as follows:

    a. If the actual costs of the New CIS are less than $118.7 million, then the $71.4 million amount included in the January 1, 2013 opening rate base for the New CIS shall be appropriately adjusted downwards;

    b. No capital costs in addition to the amount of $118.7 million will be eligible for closure to rate base on January 1, 2013, unless Enbridge Gas Distribution then demonstrates the reasonableness and prudence of such additional costs; and on the further condition that the only additional amounts eligible for consideration will be confined to increases in the system integrator costs beyond the $42 million provision for those costs included within the budget of $118.7 million.

On this basis, and subject to later adjustment as described at point 2 above, the parties request the Board, as part of the approval of this Settlement Proposal, to approve the prudence and $118.7 million cost of the new CIS, which includes procurement costs of $5.1 million.

The parties agree that there are three, and only three, possible adjustments to be made later to the revenue requirement attributable to CIS for the period 2009 through 2012, as shown in Row 3 of the Template.

The first possible adjustment relates to the tax savings associated with the high Capital Cost Allowance (CCA) for IT hardware and software for the CIS asset. The high CCA produces substantial tax savings in the first two years of the asset's ten year life. The Company acknowledges and agrees that the ratepayers are to receive credit for the full value of these tax savings. The tax rules provide that Enbridge Gas Distribution will be kept whole with respect to income taxes over the full economic life of utility assets, including the 10-year life of the CIS assets. Parties disagree over when the tax savings should be reflected in revenue requirement and rates.

To support a settlement, the parties agree, for ratemaking purposes, to the use of the values included in Row 3 of the Template in determining the revenue requirement for use at True-Up Time. Those values are calculated as if the CIS costs, including tax savings, were calculated on a conventional forward test year cost of service basis for each year during the period 2009-2012. The Company has agreed to use this assumption on the understanding that Enbridge Gas Distribution retains the right to bring an application before the Board seeking a different approach to the timing of when the tax savings are reflected in revenue requirement. Enbridge Gas Distribution agrees that it will, if it elects to make such application, file that application by June 30, 2007. Intervenors' rights to oppose any such application remain unfettered and they retain the right to rely on any and all grounds of opposition considered by them to be appropriate. The parties agree that there will be no inference that Enbridge Gas Distribution has tacitly acquiesced to values in Row 3, by accepting them in this Supplementary Settlement Agreement, and all parties acknowledge that the Company's acceptance of the values in Row 3 is "without prejudice" to the application described above, should the Company decide to file it by June 30, 2007. In the event that the Board approves a different approach to the timing of when the tax savings are reflected in revenue requirement, then parties agree that the values shown in Row 3 of the Template are to be adjusted accordingly. If Enbridge Gas Distribution does not file such an application by June 30, 2007, or if Enbridge Gas Distribution files such an application but the relief requested is not granted, then, subject to the remaining possible adjustments described below, the values in Row 3 of the Template will remain as stated therein.

The two remaining potential adjustments to the CIS revenue requirement amounts for the period 2009 through 2012, as shown in Row 3 of the Template, pertain to Enbridge Gas Distribution's equity ratio and the possibility that the system integrator contract costs resulting from the CIS procurement process are less than $42 million.

The amounts in Row 3 of the Template reflect a 35% level of deemed equity for the Company. The issue of the appropriate level of deemed equity for the Company is currently before the Board in this F2007 rate case, and there may be changes from the 35% level. Parties agree that the amounts in Row 3 of the Template should be adjusted at True-Up Time in the event that the Company's level of deemed equity is changed in the Board's decision in the F2007 rate case.

The amounts in Row 3 of the Template reflect a $118.7 million cost for the new CIS. In the event that the system integrator contract costs arrived at through the CIS RFP process are less than $42 million, then parties agree that the amounts in Row 3 should be adjusted accordingly. In the event that the system integrator costs are $42 million or more, then the parties agree to the cost of $118.7 million for the term of this agreement.

Subject to the outcome of any application which Enbridge Gas Distribution may bring before the Board, as described above, Enbridge Gas Distribution agrees that once the outstanding items on the Template are determined, and completed, and as a result the Normalized 2008 Customer Care Revenue Requirement is established, the Company will not seek any adjustment to its rates or revenue requirement relating to the cost of the new CIS during the term of this agreement. Intervenors similarly agree that they will not seek adjustments to the Company's rates or revenue requirement that are directly or indirectly based on changes in CIS costs.

Notwithstanding the limitations expressed in the preceding paragraphs, the parties agree that in the event that new legislative or regulatory requirements, that are currently unknown and that are beyond the Company's control, are imposed on the Company, in the period up to and including 2012, and those requirements materially change the level of CIS costs, then any of the parties shall be entitled to make application to the Board for adjustments to rates or revenue requirement as appropriate. The materiality threshold that applies to this aspect of the agreement will be established at the IR proceeding. The parties agree that the rights conferred in this paragraph will be no greater than any rights to revisit any issue based on changes in legislative or regulatory requirements that are established as part of the IR rules that apply to the Company.

(v) Future revenue-generating opportunities from the new CIS

The Company agrees to use its best efforts to identify and take advantage of opportunities to use the new CIS asset to provide CIS services to third party organizations to generate additional revenue opportunities, and that the gains from any such opportunities shall be shared with ratepayers in a manner to be agreed upon. A consultative group, including Intervenors, may be convened to consider how such opportunities would be addressed. The parties agree that, in the event that the sharing of such gains cannot be agreed upon by the parties, then they will put the issue of the appropriate gainsharing to be used to the Board. The parties agree that any gains to be shared with ratepayers would be cleared to ratepayers by way of an annual adjustment to delivery rates.

Billing services on the Enbridge Gas Distribution bill are covered by the Supplementary Settlement Proposal related to open bill access (Ex. N1-1-1, Appendix C), and are not included in or affected by the provisions set out above.

APPENDIX A – TRUE-UP RULES

Attached to this Appendix A is a document entitled "Customer Care and CIS Settlement Template" (the "Template"). The parties have completed each of the boxes A1 through G17 of the Template, by inserting a dollar amount, or zero, or a TBD (To Be Determined) which will be completed at the True-Up Time. The following rules apply to the completion of the Template:

1) Where in the Template there is a dollar figure or zero already inserted in any box, that figure is agreed by the parties, and subject to paragraphs 3, 4 and 6 below, will not be altered.

2) The figures agreed to by the parties which are fixed and not subject to change, and which are already included in certain boxes within the Template, include the following:

    a. Rows 1, 2 and 2a: rows 1 and 2 represent the amounts that parties agree can be recovered in rates related to payments by Enbridge Gas Distribution to ABSU to provide CIS services and the payments by ABSU to ECSI for the use of the existing CIS asset, until the new CIS asset is in service. Row 2a represents the amounts to be paid to CWLP for the use of the CIS asset from January 1, 2007 to March 31, 2007. Parties agree that a total of $28.9 million shall be included on these rows, divided into the individual amounts included in the Template.

    b. Row 4: parties agree to the figures included in the Template as the amounts to be paid for the hosting and support of the new CIS. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

    c. Row 5: parties agree to the figures included in the Template as the amounts to be recovered for the Company's backoffice costs (excluding bad debt) associated with both the old and the new CIS. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

    d. Rows 6 and 7: SAP has been chosen as the provider for the software that will support the new CIS. This software may require some modifications or adaptations, from time to time, to fully support the CIS. The parties agree to the figures included rows 6 and 7 of the Template as the amounts to be paid to SAP for licence fees and for modifications that may be necessary. These amounts are based on Enbridge Gas Distribution estimates which the Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

e. Row 8: box 8A includes the amount of $16.9 million, which is the amount that parties have agreed can be recovered in rates related to the provision of Customer Care services by CWLP for the period from January 1, 2007 to March 31, 2007 (which is the date on which ABSU will begin providing Customer Care services on a temporary or permanent basis). Given that CWLP will stop providing services to Enbridge Gas Distribution as of April 2007, the amounts to be reflected in boxes 8B, 8C, 8D, 8E and 8F are zero.

f. Row 11: parties agree to the figures included in the Template as the amounts to be recovered for Customer Care licences to support the existing and new Customer Care service provider delivery of Collections, E-Billing and text to speech voice capability functions. These amounts are based on Enbridge Gas Distribution estimates which Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

g. Row 12: parties agree to the figures included in the Template as the amounts to be recovered for the Company's backoffice costs (excluding bad debt) associated with Customer Care services. These amounts are based on Enbridge Gas Distribution estimates which Intervenors, with the support of their consultants, have reviewed and found to be reasonable.

h. Row 13: this row includes the costs incurred by the Company, and accepted for recovery from ratepayers, related to the procurement of a new customer care service provider. The parties have agreed that a total amount of $4.9 million may be recovered at row 13. This total amount represents the internal and external procurement costs for the new Customer Care services that have been determined by the parties to be prudently incurred and reasonable for recovery from ratepayers. This total amount is allocated equally over the five years from 2008 to 2012. Thus, the amount of $0.98 million is inserted in each of the boxes A13 to F13.

i. Row 17: the total number of customers for each year.

3) Row 3 includes the revenue requirement associated with the new CIS for each of the years from 2007 to 2012, to be filled in as follows:

a. The amounts in boxes A3 and B3 shall be zero, since there is no revenue requirement associated with the new CIS until 2009.

b. The amounts in boxes C3, D3, E3 and F3 represent the annual revenue requirement associated with each of 2009, 2010, 2011 and 2012 for the new CIS. These amounts, which total $46.210 million, are based upon the agreed-upon cost of the new CIS of $118.7 million. The derivation of these amounts is set out in the spreadsheets attached as Appendix B and the total of $46.210 million is the sum of the items in Columns 1, 2, 3 and 4 at line 12 on the first page of Appendix B. These amounts are subject to adjustment as follows:

   i. the amounts in row 3 of the Template reflect a $118.7 million cost for the new CIS. In the event that the system integrator contract costs arrived at through the CIS RFP process are less than $42 and the overall cost is therefore reduced, then parties agree that the amounts in row 3 should be changed to correspond to the lower new CIS cost;

   ii. the amounts in row 3 of the Template reflect a 35% level of deemed equity for the Company. The issue of the appropriate level of deemed equity for the Company is currently before the Board in this F2007 rate case, and there may be changes from the 35% level. Parties agree that the amounts in row 3 of the Template should be changed in the event that the Company's level of deemed equity is changed;

   iii. In the event that the Company is successful in an application to the Board for a different approach to the timing of when tax savings associated with the new CIS are reflected in revenue requirement, then corresponding changes will be made to the amounts in row 3.

4) The amounts to be inserted in boxes A9 and B9 shall be determined by the parties as the prudent and reasonable amounts for recovery from ratepayers for sums paid or forecast to be payable by the Company to ABSU for Customer Care services during the period April 1, 2007 through September 30, 2008, in accordance with the following criteria:

   a. In the event that ABSU is chosen as the new service provider for Customer Care services from and after April 1, 2007 until December 31, 2012, then the figures to be inserted in boxes A9 and B9 are zero, because there will be no need for a transition period to a new service provider;

b. In the event that a third party other than ABSU is chosen as the new service provider for Customer Care services, then there will be the need for a transition period, for a maximum of 18 months from April 1, 2007, during which ABSU will provide Customer Care services until the new service provider can be fully phased-in.

c. The Company has reached agreement with ABSU for Customer Care services to be provided, on a transition basis for 2007 and 2008 in the event that ABSU is not the successful Customer Care bidder. For settlement purposes, subject to subparagraph (d) below, the Parties agree that amounts of up to $52,263,000 for 2007 and $42,623,000 for 2008 will be included in boxes A9 and B9. These numbers represent the maximum agreed-upon level of costs that the Company may recover in rates in respect of the amounts charged by ABSU during 2007 and 2008 for Customer Care services, on a transitional basis, based on a recoverable cost of $38 per customer per year and a transition period of 18 months;

d. The Company will make best efforts to reduce the length of the transition period from 18 months, and to reduce the actual forecast costs per customer from ABSU to be less than currently forecast. In the event that the actual costs to date and updated forecast costs from ABSU at True-up Time for Customer Care services for the transition period are less than $52,263,000 for 2007 or $42,623,000 for 2008, then the numbers to be inserted in boxes A9 and B9 will be the actual costs to date and updated forecast costs at True-Up Time.

e. The amounts to be inserted in boxes C9, D9, E9 and F9 are zero because, in any event, the transition period for customer care services will not extend beyond 2008.

5) The amounts to be inserted in boxes A10 to F10 are the reasonable forecast annual costs of the new Customer Care service provider, to be determined at the True-Up Time through the results of the Customer Care procurement process. In the event that ABSU is chosen as the new service provider, it is expected that these amounts will be effective as of April 1, 2007. In the event that a third party other than ABSU is chosen as the new service provider, it is expected that these amounts will begin at some time in 2007 or 2008, because of the need for transition time and activities. The amounts to be included in these boxes are subject to review by the Consultative for prudence and reasonableness. In the event that the Intervenors and the Company do not agree, the issue of prudence and reasonableness will be determined by the Board.

6) The amounts at rows 14 and 15 represent the transition costs associated with moving from CWLP as the Customer Care service provider to a different third party service provider. The transition costs to be included in these rows, and tracked in the 2007 and 2008 Customer Care Transition Costs Variance Accounts, relate to activities that ABSU and external contractors and internal resources will undertake to transfer knowledge and services to the new service provider. This will include such tasks as training, documentation and management of the vendors through the transition.

   a. In any event, the number in boxes A14/A15 will be zero.

   b. In the event that ABSU is chosen as the new Customer Care service provider then the amounts to be inserted in boxes B14 to F14 and B15 to F15 are zero and subparagraphs 6(c) to (f) do not apply.

   c. In the event that a different third party is chosen as the new Customer Care service provider, then a total amount of $11.1 million will be included on rows 14 and 15. This total amount will be split equally between the years 2008 to 2012, in the amount of $2.22 million per year. Thus, each of boxes B14/B15, C14/C15, D14/D15, E14/E15 and F14/F15 will include the number $2.22 million.

   d. The Company will record all prudent and reasonable amounts spent for services, both internal and external, to facilitate the transition from CWLP/ABSU providing Customer Care services to a new service provider in the 2007 and 2008 Customer Care Transition Costs Variance Accounts, to a total maximum of $11.1 million. It is agreed that amounts paid for internal costs shall not include the costs of employees or other resources already included in the budget for the year and re-assigned to this transition, unless a specific new resource was acquired to backfill those other functions.

   e. Commencing in 2008, and continuing each year until 2012, the Company will expense the amount of $2.22 million for Customer Care costs, and will at the same time, deduct the same amount from the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts. The parties agree that, even if the outstanding balance in the 2007 and 2008 Customer Care Transition Costs Variance Accounts becomes zero before 2012, the Company is still entitled to expense and recover the amount of $2.22 million for each year until 2012. The parties further agree that no negative balances will be reflected in the 2007 and 2008 Customer Care Transition Costs Variance Accounts.

f. Parties agree that if the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts are less than $11.1 million as of December 31, 2008, then the difference between $11.1 million and the total amounts recorded in the 2007 and 2008 Customer Care Transition Costs Variance Accounts will be credited to ratepayers with interest in equal amounts in 2009 to 2012.

7) Row 16 will be the totals of each of the columns, to be completed when all of the above figures are determined.

8) Column G will be the totals of each of the rows, to be completed when all of the above figures are determined.

9) Box G16 will be the total of all Customer Care costs and revenue requirement forecast for the period (the "Total Customer Care Forecast").

10) Box G17, already completed, is the forecast total of annual numbers of customers during the period (the "Customer Count").

At True-Up Time, once the Template has been completed, then the Normalized 2007 Customer Care Revenue Requirement can be determined. This will be calculated by starting with the Total Customer Care Revenue Requirement for 2007 to 2012, which is the sum of boxes A16 to F16. That Total Customer Care Revenue Requirement will then be placed into an amortization model that calculates, using the IR annual adjustment that is approved for Enbridge Gas Distribution, the Normalized 2007 Customer Care Revenue Requirement which is the number that, when adjusted for IR annual adjustment for each year from 2008 through 2012, would allow the Company to fully recover the Adjusted Customer Care Revenue Requirement for 2007 to 2012.

At the same time, parties will calculate the 2007 Customer Care Revenue Requirement Variance by taking the difference between the Normalized 2007 Customer Care Revenue Requirement and the placeholder of $90.8 million. The Company will credit or debit the 2007 Customer Care Revenue Requirement Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012.

Attached to this Appendix A is an illustrative example of how the True-Up will be applied. For the purpose of this example, the following assumptions have been employed: (i) at row 3, the CIS cost is recovered by recognizing the tax shield benefit in the first four years, and a deemed equity level of 35% is assumed; (ii) ABSU is not awarded the Customer Care contract, so there are transition costs included at row 9; (iii) at row 10, the new CIS service provider contract cost is $60 million per year; and (iv) the

IR Annual Adjustment is 1%. The illustrative example sets out the steps that are followed, and the amortization model that is used, to derive the 2007 Customer Care Revenue Requirement Variance and the Normalized Customer Care Revenue Requirements for 2007 to 2012.

Customer Care and CIS Settlement Template

#	Category of Cost	A 2007	B 2008	C 2009	D 2010	E 2011	F 2012	G Totals
	CIS Related Categories							
1	*Old CIS Licence Fee*							
2	*Old CIS Hosting and Support*	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000
2a	*Incumbent (CWLP) CIS Services being provided from January to March 2007*							
3	*New CIS Capital Cost*	$0	$0	$880,000	($5,340,000)	$25,810,000	$24,860,000	$46,210,000
4	*New CIS Hosting and Support*	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000
5	*CIS Backoffice (EGD Staffing)*	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254
6	*SAP Licence Fees*	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500
7	*SAP Modifications*	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000
	Customer Care Related Categories							
8	*Incumbent (CWLP) Customer Care Services being provided from - January to March 2007*	$16,900,000	$0	$0	$0	$0	$0	$16,900,000
9	*Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sep 30, 2008*	Up to $52,263,000	Up to $42,623,000	$0	$0	$0	$0	$0
10	*New Service Provider Contract Cost*	TBD	TBD	TBD	TBD	TBD	TBD	$0
11	*Customer Care Licences*	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000
12	*Customer Care Backoffice (EGD staffing)*	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071
13	*Customer Care Procurement Costs*	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000
14	*Transition Costs - Consultants and ISP*	$0	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$11,100,000
15	*Transition Costs - EGD Staffing*							
16	**Total CIS & Customer Care**	TBD	TBD	TBD	TBD	TBD	TBD	TBD
17	*Number of Customers*	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613

Customer Care and CIS Settlement Template - Example for purpose of illustrating True-Up

#	Category of Cost	A 2007	B 2008	C 2009	D 2010	E 2011	F 2012	G Totals
	CIS Related Categories							
1	*Old CIS Licence Fee*							
2	*Old CIS Hosting and Support*	$14,200,000	$9,800,000	$4,900,000	$0	$0	$0	$28,900,000
2a	*Incumbent (CWLP) CIS Services being provided from January to March 2007*							
3	*New CIS Capital Cost (Intervenor Model @ 35% Equity)*	$0	$0	$880,000	($5,340,000)	$25,810,000	$24,860,000	$46,210,000
4	*New CIS Hosting and Support*	$0	$0	$4,350,000	$8,700,000	$8,700,000	$8,700,000	$30,450,000
5	*CIS Backoffice (EGD Staffing)*	$1,000,000	$1,030,000	$2,000,000	$2,060,000	$2,121,800	$2,185,454	$10,397,254
6	*SAP Licence Fees*	$0	$0	$1,113,500	$2,227,000	$2,227,000	$2,227,000	$7,794,500
7	*SAP Modifications*	$0	$0	$1,000,000	$1,000,000	$0	$0	$2,000,000
	Customer Care Related Categories							
8	*Incumbent (CWLP) Customer Care Services being provided from - January to March 2007*	$16,900,000	$0	$0	$0	$0	$0	$16,900,000
9	*Customer Care Transition Service Provider Contract Cost - ABSU April, 2007 to Sep 30, 2008*	$52,263,530	$42,623,220	$0	$0	$0	$0	$94,886,750
10	*New Service Provider Contract Cost - (Values placed for illustrative purposes)*	$0	$24,000,000	$60,000,000	$60,000,000	$60,000,000	$60,000,000	$264,000,000
11	*Customer Care Licences*	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$1,400,000	$8,400,000
12	*Customer Care Backoffice (EGD staffing)*	$3,100,000	$3,193,000	$3,288,790	$3,387,454	$3,489,077	$3,593,750	$20,052,071
13	*Customer Care Procurement Costs*	$0	$980,000	$980,000	$980,000	$980,000	$980,000	$4,900,000
14	*Transition Costs - Consultants and ISP*	$0	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$2,220,000	$11,100,000
15	*Transition Costs - EGD Staffing*							
16	**Total CIS & Customer Care**	$88,863,530	$85,246,220	$82,132,290	$76,634,454	$106,947,877	$106,166,204	$545,990,575
17	*Number of Customers*	1,831,283	1,878,004	1,925,563	1,973,575	2,021,588	2,069,600	11,699,613

	True-Up Process Step	A	B	C	D	E	F	G
18	The Normalized 2007 Customer Care Revenue Requirement can be determined. This will be calculated by starting with the Total Customer Care Revenue Requirement for 2007 to 2012, which is the amount in box G16	$545,990,575						
19	That Total Customer Care Revenue Requirement will then be placed into an amortization model that calculates, using the IR annual adjustment that is approved for Enbridge Gas Distribution, the Normalized 2007 Customer Care Revenue Requirement which is the number that, when adjusted for IR annual adjustment for each year from 2008 through 2012, will allow the Company to fully recover the Total Customer Care Revenue Requirement for 2007 to 2012	$88,749,876.15						
20	The Normalized 2007 Customer Care Revenue Requirement will then be compared to the 2007 placeholder of $90.8 million, and the difference will be the 2007 Customer Care Revenue Requirement Variance.	($2,050,124)						
21	The Company will credit or debit the 2007 Customer Care Revenue Requirement Variance, as the case may be, to the 2007 Customer Care Variance Account. The balance in that account will be repaid to the ratepayers, or charged to the ratepayers, with interest, over the course of 2008 to 2012.		($410,025)	($410,025)	($410,025)	($410,025)	($410,025)	
22	The Normalized 2008 Customer Care Revenue Requirement will be the Normalized 2007 Customer Care Revenue Requirement, plus or minus the IR annual adjustment that is approved for Enbridge Gas Distribution.		$89,637,375	$90,533,749	$91,439,086	$92,353,477	$93,277,012	
23	**Total Customer Care Revenue By Year (Including repayment of 2007 variance)**	$ 90,800,000	$ 89,227,350	$ 90,123,724	$ 91,029,061	$ 91,943,452	$ 92,866,987	$ 545,990,575
24	Normalized Customer Care Revenue Requirement Per Customer without Bad Debt	$ 49.58	$ 47.51	$ 46.80	$ 46.12	$ 45.48	$ 44.87	
25	*IR Annual Adjustment*	*1%*						

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Capital Structure
65% Incremental Long Term Debt / 35% Equity

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Component	Indicated Cost Rate	Return Component	(4 dec.) Return Component
		%	%	%	%
1.	Long-term debt	65.00	5.35	3.48	3.4775
2.	Short-term debt	0.00	0.00	0.00	0.0000
3.		65.00		3.48	3.4775
4.	Preference shares	0.00	0.00	0.00	0.0000
5.	Common equity	35.00	8.39	2.94	2.9365
6.		100.00		6.42	6.4140

	($Millions)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
7.	Ontario Utility Income ($M)	6.69	9.89	(10.77)	(10.92)	(11.07)	(11.22)	(11.37)	(11.52)	(11.67)	(11.81)
8.	Rate base ($M)	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
9.	Indicated rate of return %	5.921 %	9.783 %	(12.074)%	(14.125)%	(16.921)%	(20.963)%	(27.311)%	(38.734)%	(65.372)%	(198.101)%
10.	(Deficiency) in rate of return %	(0.493)%	3.369 %	(18.488)%	(20.539)%	(23.335)%	(27.377)%	(33.725)%	(45.148)%	(71.786)%	(204.515)%
11.	Net (deficiency) ($M)	(0.56)	3.41	(16.49)	(15.88)	(15.27)	(14.65)	(14.04)	(13.43)	(12.81)	(12.19)
12.	Gross (deficiency) ($M)	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.05)	(19.08)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Rate Base

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Property, plant, and equipment										
1.	Cost or redetermined value	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93	118.93
2.	Accumulated depreciation	(5.95)	(17.84)	(29.73)	(41.62)	(53.51)	(65.41)	(77.30)	(89.19)	(101.08)	(112.97)
3.	Net Property, plant, and equipment	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
	Allowance for working capital										
4.	Accounts receivable merchandise finance plan	-	-	-	-	-	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-	-	-	-	-	-
12.		-	-	-	-	-	-	-	-	-	-
13.	Ontario utility rate base	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Income

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Revenue										
1.	Gas sales	-	-	-	-	-	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-	-	-	-	-	-
4.	Storage service	-	-	-	-	-	-	-	-	-	-
5.	Other operating revenue	-	-	-	-	-	-	-	-	-	-
6.	Interest and property rental	-	-	-	-	-	-	-	-	-	-
7.	Other income	-	-	-	-	-	-	-	-	-	-
8.	Total revenue	-	-	-	-	-	-	-	-	-	-
	Costs and expenses										
9.	CIS -selection procurement cost	5.10	-	-	-	-	-	-	-	-	-
10.	Operation and maintenance	-	-	-	-	-	-	-	-	-	-
11.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
12.	Provincial capital taxes	0.16	-	-	-	-	-	-	-	-	-
13.	Total costs and expenses	17.15	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
14.	**Utility income before inc. taxes**	(17.15)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)
	Income taxes										
15.	Excluding interest shield	(22.42)	(20.51)	-	-	-	-	-	-	-	-
16.	Tax shield on interest expense	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
17.	Total income taxes	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
18.	**Ontario utility net income**	6.69	9.89	(10.77)	(10.92)	(11.07)	(11.22)	(11.37)	(11.52)	(11.67)	(11.81)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Taxable Income and Income Tax Expense

($Millions)

Line No.		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1.	Utility income before income taxes	(17.15)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)	(11.89)
	Add Backs										
2.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
3.	Large corporation tax	-	-	-	-	-	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-	-	-	-	-	-
6.	Total added back	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
7.	Sub total - pre-tax income plus add backs	(5.26)	-	-	-	-	-	-	-	-	-
	Deductions										
8.	Capital cost allowance - Federal	56.80	56.80	-	-	-	-	-	-	-	-
9.	Capital cost allowance - Provincial	56.80	56.80	-	-	-	-	-	-	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-	-	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-	-	-	-	-	-
16.	Total Deductions - Federal	56.80	56.80	-	-	-	-	-	-	-	-
17.	Total Deductions - Provincial	56.80	56.80	-	-	-	-	-	-	-	-
18.	Taxable income - Federal	(62.06)	(56.80)	-	-	-	-	-	-	-	-
19.	Taxable income - Provincial	(62.06)	(56.80)	-	-	-	-	-	-	-	-
20.	Income tax provision - Federal @ 22.12 %	(13.73)	(12.56)	-	-	-	-	-	-	-	-
21.	Income tax provision - Provincial @ 14.00 %	(8.69)	(7.95)	-	-	-	-	-	-	-	-
22.	Income tax provision - combined	(22.42)	(20.51)	-	-	-	-	-	-	-	-
23.	Part V1.1 tax	-	-	-	-	-	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(22.42)	(20.51)	-	-	-	-	-	-	-	-
	Tax shield on interest expense										
26.	Rate base as adjusted	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
27.	Return component of debt	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%	3.4775%
28.	Interest expense	3.93	3.52	3.10	2.69	2.28	1.86	1.45	1.03	0.62	0.21
29.	Combined tax rate	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612	0.3612
30.	Income tax credit	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
31.	**Total income taxes**	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)

Appendix B

Utility Owned CIS System
10 Year Life
Ontario Utility Revenue Requirement

Line No.	**($Millions)**	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Cost of capital										
1.	Rate base	112.98	101.09	89.20	77.31	65.42	53.52	41.63	29.74	17.85	5.96
2.	Required rate of return	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%	6.4140%
3.	Cost of capital	7.25	6.48	5.72	4.96	4.20	3.43	2.67	1.91	1.15	0.38
	Cost of service										
4.	CIS -selection procurement cost	5.10	-	-	-	-	-	-	-	-	-
5.	Operation and maintenance	-	-	-	-	-	-	-	-	-	-
6.	Depreciation and amortization	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
7.	Municipal and other taxes	0.16	-	-	-	-	-	-	-	-	-
8.	Cost of service	17.15	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89	11.89
	Misc. & Non-Op. Rev										
9.	Other operating revenue	-	-	-	-	-	-	-	-	-	-
10.	Other income	-	-	-	-	-	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-	-	-	-	-	-
	Income taxes on earnings										
12.	Excluding tax shield	(22.42)	(20.51)	-	-	-	-	-	-	-	-
13.	Tax shield provided by interest expens	(1.42)	(1.27)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
14.	Income taxes on earnings	(23.84)	(21.78)	(1.12)	(0.97)	(0.82)	(0.67)	(0.52)	(0.37)	(0.22)	(0.08)
	Taxes on deficiency										
15.	Gross deficiency	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.05)	(19.08)
16.	Net deficiency	(0.56)	3.41	(16.49)	(15.88)	(15.27)	(14.65)	(14.04)	(13.43)	(12.81)	(12.19)
17.	Taxes on deficiency	0.32	(1.93)	9.32	8.98	8.63	8.28	7.94	7.59	7.24	6.89
18.	**Revenue requirement**	0.88	(5.34)	25.81	24.86	23.90	22.93	21.98	21.02	20.06	19.08
	Revenue at existing Rates										
19.	Gas sales	-	-	-	-	-	-	-	-	-	-
20.	Transportation service	-	-	-	-	-	-	-	-	-	-
21.	Transmission, compression and storag	-	-	-	-	-	-	-	-	-	-
22.	Rounding adjustment	-	-	-	-	-	-	-	-	-	-
23.	Revenue at existing rates	-	-	-	-	-	-	-	-	-	-
24.	**Gross revenue deficiency**	(0.88)	5.34	(25.81)	(24.86)	(23.90)	(22.93)	(21.98)	(21.02)	(20.06)	(19.08)

2007 TEST YEAR
FINANCIAL IMPACT OF THE SETTLEMENT PROPOSAL

1. This exhibit is being filed in order to provide the Board with the financial impact of the Settlement Proposal filed at Exhibit N1.T1.S1 against the Company's updated deficiency request filed at Exhibit M1, Tab 2, Schedule 1. Acceptance of the Settlement Proposal will decrease the Company's gross revenue deficiency in the 2007 Test Year by $76.7 million, from $158.7 million as shown at Exhibit M1.T2.S1, to $82.0 million as shown at Exhibit N1, Tab 2, Schedule 2. The $82.0 million gross deficiency amount includes within it, a gross deficiency amount of $29.9 million related to issues which have been agreed to in the Settlement Proposal, and a gross deficiency amount of $52.1 million relating to issues which remain unresolved. The financial adjustments which achieve the $82.0 million deficiency amount are shown within Schedules 2 through 6 of this exhibit while the adjustments which result in the $29.9 million deficiency are shown within Schedule 2, pages 1 and 2.

Rate Base (Exhibit N1.T2.S3)

2. The Company's rate base forecast will decrease by $54.6 million, from $3,798.3 million at Exhibit M1.T2.S2 to $3,743.7 million at Exhibit N1.T2.S3, p.1, Line 13, as a result of the Settlement Proposal.

3. The $56.4 million reduction to the property, plant and equipment portion of rate base is the summary impact of reductions to the capital expenditure budget (Exhibit N1.T1.S1 – Issues 1.1 through 1.8) and the removal of the proposed changes to depreciation rates within the depreciation study (Exhibit N1.T1.S1 – Issue 3.11).

Witness: K. Culbert

4. The working cash allowance component of rate base has been recalculated to reflect the impact of the Settlement Proposal with respect to the decrease in operation and maintenance costs included in the calculation (Exhibit N1.T1.S1. – Issues 1.6 and 3.2), resulting in a $1.8 million increase. A decrease in O&M results in an increase in working cash allowance because of the negative O&M lag day factor embedded in the calculation. A negative O&M lag day factor multiplied by a reduced O&M value, results in a lower credit within the working cash allowance calculation and thus a higher total working cash allowance. The working cash allowance calculation of $2.5 million is filed at Exhibit N1.T2.S3, on page 3, and compares to the level of $0.7 million filed at Exhibit M1.T2.S2, page 3.

Utility Income (Exhibit N1.T2.S4)

5. Acceptance of the Settlement Proposal will result in an increase to the Company's forecast of net income in the amount of $46.2 million, from $188.4 million at Exhibit M1.T2.S3 to $234.6 million at Exhibit N1.T2.S4, pg.1, line 22. The individual revenue and expense items which have been adjusted as a result of the Settlement Proposal can be examined at Exhibit N1.T.2.S4, on pages 1 through 3, and are discussed in the following paragraphs.

6. Other operating revenue will increase by $5.2 million, from $23.7 million at Exhibit M1.T2.S3, line 4 to $28.9 million at Exhibit N1.T2.S4, pg.1, line 4, as a result of the Settlement Proposal for the following:
   - Transactional Services revenue increase of $3.5 million (Exhibit N1.T1.S1 – Issue 2.1),
   - Service charges & DPAC revenue increase of $1.0 million (Exhibit N1.T1.S1 – Issue 2.2); and
   - imputed NGV program revenue of $0.7 million (Exhibit N1.T1.S1 - Issue 2.2).

7. As a result of the Settlement Proposal relating to DSM, Corporate Cost Allocation and Other O&M, operation and maintenance costs will decrease by $24.1 million, from $365.8 million at Exhibit M1.T2.S3, pg.1, line 9 to $341.7 million at Exhibit N1.T2.S4, pg.1, line 9. This is the result of a $0.5 million EnVision related other O&M reduction, a further $18.8 million general reduction to other O&M and a $4.8 million reduction to the corporate cost allocation amount as agreed to in the Settlement Proposal (Exhibit N1.T1.S1 – Issues 1.6 & 3.2).

8. Depreciation and amortization expense decreases by $27.5 million as a result of the Settlement Proposal. Of this decrease, $24.8 million is due to the agreed upon withdrawal of the depreciation rate changes within the proposed depreciation study (Exhibit N1.T1.S1 – Issue 3.11) while $2.7 million is due to the agreed upon reductions to capital expenditures (Exhibit N1.T1.S1 – Issues 1.1 through 1.8).

9. Municipal and other taxes will decrease by $1.7 million, from $47.6 million at Exhibit M1.T2.S3, pg.1, line 14 to $45.9 million (Exhibit N1.T2.S4, pg.1, line 14) as a result of a general reduction to municipal and other taxes of $1.3 million within the Settlement Proposal (Exhibit N1.T1.S1 – Issue 3.14) and a reduction in capital taxes due to capital expenditure reductions within the Settlement Proposal at (Exhibit N1.T1.S1 – Issues 1.1 through 1.8).

10. As a result of the Settlement Proposal, Utility income before income taxes will increase by $58.5 million, which will result in an increase in income taxes excluding the tax shield provided by interest expense in the amount of $12.0 million. The tax shield provided by interest expense will decrease by $0.3 million as a result of the decline in rate base of $54.6 million (Exhibit N1.T2.S3, pg.1, line 13). The decrease

in the tax shield provided by interest expense associated with the decline in rate base is partially offset by a 0.04% increase in the capital structure return component of long and short-term debt which has increased from 4.31% as filed at Exhibit M1.T2.S4, pg.1, Line 3, Col. 4 to 4.35% found at Exhibit N1.T2.S5, pg.1, line 3, Col. 4. Total income taxes will increase by $12.3 million, from $48.1 million filed at Exhibit M1.T2.S3, pg.1, line 21 to $60.4 million at Exhibit N1.T2.S4, pg.1, line 21.

Capital Structure (Exhibit N1.T2.S5)

11. The proposed method and costs of financing capital requirements have been incorporated into the capital structure found (Exhibit N1.T2.S5, pg.1). The overall rate of return on rate base of 7.67% includes an 8.39% rate of return on common equity as determined by the current Board approved formula as agreed to in the Settlement Proposal. (Exhibit N1.T1.S1 - Issue 4.1)

12. Utility income in the amount of $234.6 million represents an indicated return of 6.27% on a rate base of $3,743.7 million, indicating a deficiency in return in the amount of 1.40% in comparison to the requested overall rate of return of 7.67%. This results in a net deficiency of $52.4 million and a gross revenue deficiency of $82.0 million, as shown at Exhibit N1, Tab 2, Schedule 5.

13. Acceptance of the Settlement Proposal will result in a gross revenue deficiency of $82.0 million, which is a decrease of $76.7 million, as shown at Exhibit N1, Tab 2, Schedule 6, in comparison to the Company's deficiency request filed at Exhibit M1, Tab 2, Schedules 4 & 5 in the amount of $158.7 million.

Utility ADR Impact Summary
2007 Test Year

Line No.		Col. 1 Reference	Col. 2 ($Millions)
1.	Utility rate base	N1.T2.S3.P1*	3,743.7
2.	Utility income	N1.T2.S4.P1	234.6
3.	Indicated rate of return	N1.T2.S5.P1	6.27%
4.	Requested rate of return	N1.T2.S5.P1	7.67%
5.	(Deficiency) in rate of return	N1.T2.S5.P1	(1.40)%
6.	Net (deficiency)	N1.T2.S5.P1	(52.4)
7.	Gross (deficiency)	N1.T2.S5.P1	(82.0)
8.	Revenue at existing rates	N1.T2.S6.P1	3,071.8
9.	Revenue requirement	N1.T2.S6.P1	3,153.8
10.	Gross revenue (deficiency)	N1.T2.S6.P1	(82.0)
11.	Unsettled Issues and Gross deficiency amounts to be resolved (N1.T2.S2.page 2)		52.1
12.	ADR Resolved Issues and embedded Gross Deficiency		(29.9)

*N1.T2.S2.P1 refers to Exhibit N1, Tab 2, Schedule 2, page 1.

2007 Test Year
Deficiency for Implementation April 1, 2007

Line No.		Col. 1 Gross Deficiency Amount ($millions)
1.	Post ADR Settlement Proposal Gross Deficiency (includes deficiency amounts for settled and unsettled / unresolved issues)	(82.0)
	Unsettled / Unresolved Issues and embedded Deficiency amounts	
2.	Customer support costs in filing vs. in existing rates ($120.1 vs. 104.1)	16.0
3.	Transition costs in filing versus in existing rates	10.0
4.	Equity at 38% versus 35% in existing rates (Updated 2007-01-18, A2.T5.S1, col.4)	10.0
5.	Change in volumes deficiency impact (Updated 2007-01-18, A2.T5.S1, col.2)	16.1
6.	Sub-total Unsettled / Unresolved Issues and Gross Deficiency	52.1
7.	ADR Resolved Issues and embedded Gross Deficiency	(29.9)

Utility Rate Base
2007 Test Year

Line No.		Col. 1 Impact No.1 Filed: 2006-12-06 M1.T2.S2	Col. 2 Adjustments	Col. 3 ADR Utility Rate Base
		($Millions)	($Millions)	($Millions)
	Property, plant, and equipment			
1.	Cost or redetermined value	5,048.3	(69.6)	4,978.7
2.	Accumulated depreciation	(1,852.6)	13.2	(1,839.4)
3.		3,195.7	(56.4)	3,139.3
	Allowance for working capital			
4.	Accounts receivable merchandise finance plan	0.1		0.1
5.	Accounts receivable rebillable projects	6.9		6.9
6.	Materials and supplies	21.0		21.0
7.	Mortgages receivable	0.9		0.9
8.	Customer security deposits	(42.8)		(42.8)
9.	Prepaid expenses	2.7		2.7
10.	Gas in storage	613.1		613.1
11.	Working cash allowance	0.7	1.8	2.5
12.	Total Working Capital	602.6	1.8	604.4
13.	**Utility rate base**	3,798.3	(54.6)	3,743.7

Explanation of Adjustments to Utility Rate Base
2007 Test Year

Line No. Adj'd	Adjustments ($Millions)	Explanation
1.	(69.6)	**Cost or redetermined value**
		To reflect the impact of capital expenditure reductions, due to the settlement of Issues 1.1 through 1.8, on the value of gross plant within rate base.
2.	13.2	**Accumulated depreciation**
		To reflect the impact on accumulated depreciation arising from capital expenditure reductions due to the settlement of Issues 1.1 through 1.8, and from a return to the use of existing Board Approved depreciation rates as a result of the settlement of Issue 3.11.
11.	1.8	**Working cash allowance**
		To reflect the impact on the Company's working cash allowance as a result of changes to operation and maintenance expenses as per the Settlement Proposal. An explanation of changes to operation and maintenance expenses can be found in Exhibit N1, Tab 2, Schedule 4. The working cash allowance calculation can be found on Exhibit N1, Tab 2, Schedule 3, page 3.

Working Capital Components - Working Cash Allowance
2007 Test Year

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		2,265.7	3.7	23.0
2.	Items not subject to working cash allowance	(Note 1)	(95.1)		
3.	Gas costs charged to operations		2,170.6		
4.	Operation and Maintenance		341.7		
5.	Less: Storage costs		(6.9)		
6.	Operation and maintenance costs subject to working cash		334.8	(27.4)	(25.1)
7.	Sub-total				(2.1)
8.	Storage costs		6.9	52.9	1.0
9.	Storage municipal and capital taxes		1.5	35.5	0.1
10.	Sub-total				1.1
11.	Goods and services tax				3.5
12.	Total working cash allowance				2.5

Note 1: Represents non-cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

Gas in Storage
Month End Balances and Average of Monthly Averages
2007 Test Year

Line No.		Volume 10*6 M*3	Col. 1 Impact No.1 Filed: 2006-12-06 M1.T2.S2 ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 ADR Value ($Millions)
1.	January 1	1,848.2	785.3		785.3
2.	January 31	1,397.6	589.6		589.6
3.	February	1,048.0	437.2		437.2
4.	March	809.0	333.7		333.7
5.	April	768.7	317.1		317.1
6.	May	927.1	383.7		383.7
7.	June	1,151.6	478.8		478.8
8.	July	1,411.3	588.9		588.9
9.	August	1,731.4	721.8		721.8
10.	September	2,078.1	863.1		863.1
11.	October	2,276.0	941.2		941.2
12.	November	2,220.2	912.2		912.2
13.	December	1,958.3	794.4		794.4
14.	**Avg. of monthly avgs.**	1,476.9	613.1	-	613.1

Utility Income
2007 Test Year

Line No.		Col. 1 Impact No.1 Filed: 2006-12-06 M1.T2.S3 ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 ADR Utility Income ($Millions)
	Revenue			
1.	Gas sales	2,348.9		2,348.9
2.	Transportation of gas	720.9		720.9
3.	Transmission and compression & storage	1.9		1.9
4.	Other operating revenue	23.7	5.2	28.9
5.	Interest and property rental	-		-
6.	Other income	0.2		0.2
7.	**Total revenue**	3,095.6	5.2	3,100.8
	Costs and expenses			
8.	Gas costs	2,170.6		2,170.6
9.	Operation and maintenance	365.8	(24.1)	341.7
10.	Transition costs customer care	10.0		10.0
11.	Depreciation and amortization	254.6	(27.5)	227.1
12.	Fixed financing costs	1.3		1.3
13.	Notional utility account recovery	9.2		9.2
14.	Municipal and other taxes	47.6	(1.7)	45.9
15.	Interest and financing amortization expense	-		-
16.	Other interest expense	-		-
17.	**Total costs and expenses**	2,859.1	(53.3)	2,805.8
18.	Utility income before income taxes	236.5	58.5	295.0
	Income taxes			
19.	Excluding interest shield	107.2	12.0	119.2
20.	Tax shield on interest expense	(59.1)	0.3	(58.8)
21.	Total income taxes	48.1	12.3	60.4
22.	**Utility net income**	188.4	46.2	234.6

Explanation of Adjustments to Utility Income
2007 Test Year

Line No. Adj'd	Adjustments ($Millions)	Explanation
4.	5.2	**Other operating revenue**
		To reflect the impact of a $3.5 million increase in the ratepayer guaranteed amount of Transactional Services revenue, an increase in Other Revenue of $1.0 million, and imputing revenue of $0.7 million to the NGV program as a result of the settlement of Issues 2.1 and 2.2.
9.	(24.1)	**Operation and maintenance**
		To reflect the impact of a $0.5 million Envision related O&M reduction, a $4.8 million reduction to achieve the agreed upon corporate cost allocation amount of $18.1 million, and a further $18.8 million reduction to achieve the agreed upon other O&M amount of $181.5 million per the settlement of Issues 1.6 and 3.2.
11.	(27.5)	**Depreciation and amortization**
		To reflect the impact on depreciation and amortization arising from capital expenditure reductions due to the settlement of Issues 1.1 through 1.8, and from a return to the use of existing Board Approved depreciation rates as a result of the settlement of Issue 3.11.
14.	(1.7)	**Municipal and other taxes**
		To reflect the impact of a $1.3 million reduction to municipal taxes, per the settlement of Issue 3.14, and a $0.4 million reduction to capital taxes that results from the reduction of capital expenditures agreed to in Issues 1.1 through 1.8 of the Settlement Proposal.
19.	12.0	**Income taxes - excluding interest shield**
		To reflect adjustments to utility income taxes as a result of the above noted changes contributing to higher taxable income and income tax excluding the interest tax shield. The Utility's income tax calculations are found in Exhibit N1, Tab 2, Schedule 4, page 3.

Utility Taxable Income and Income Tax Expense
2007 Test Year

Line No.		Col. 1 Impact No.1 Filed: 2006-12-06 M1.T2.S3.p3	Col. 2 Adjustments	Col. 3 ADR Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes	236.5	58.5	295.0
	Add Backs			
2.	Depreciation and amortization	254.6	(27.5)	227.1
3.	Other non-deductible items	1.2		1.2
4.	Total Add Back	255.8	(27.5)	228.3
5.	Sub total	492.3	31.0	523.3
	Deductions			
6.	Capital cost allowance - Federal	163.3	(2.4)	160.9
7.	Capital cost allowance - Provincial	163.2	(2.4)	160.8
8.	Items capitalized for regulatory purposes	28.7		28.7
9.	Deduction for "grossed up" Part VI.1 tax	5.9		5.9
10.	Amortization of share/debenture issue expense	2.6		2.6
11.	Amortization of cumulative eligible capital	0.1		0.1
12.	Amortization of C.D.E. and C.O.G.P.E	0.3		0.3
13.	Total Deduction - Federal	200.9	(2.4)	198.5
14.	Total Deduction - Provincial	200.8	(2.4)	198.4
15.	Taxable income - Federal	291.4	33.4	324.8
16.	Taxable income - Provincial	291.5	33.4	324.9
17.	Income tax provision - Federal	64.5	7.3	71.8
18.	Income tax provision - Provincial	40.8	4.7	45.5
19.	Income tax provision - combined	105.3	12.0	117.3
20.	Part V1.1 tax			2.0
21.	Investment tax credit			(0.1)
22.	Total taxes excluding tax shield on interest expense			119.2
	Tax shield on interest expense			
23.	Rate base			3,743.7
24.	Return component of debt			4.35%
25.	Interest expense			162.9
26.	Combined tax rate			36.12%
27.	Income tax credit			(58.8)
28.	Total income taxes			60.4

Utility Capital Structure
2007 Test Year

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,234.4	59.68	7.31	4.36
2.	Short term debt	(13.2)	(0.35)	4.12	(0.01)
3.		2,221.2	59.33		4.35
4.	Preference shares	99.9	2.67	5.00	0.13
5.	Common equity	1,422.6	38.00	8.39	3.19
6.		3,743.7	100.00		7.67
7.	Utility income	($Millions)			234.6
8.	Utility Rate base	($Millions)			3,743.7
9.	Indicated rate of return				6.27%
10.	(Deficiency) in rate of return				(1.40)%
11.	Net (deficiency)	($Millions)			(52.4)
12.	Gross (deficiency)	($Millions)			(82.0)
13.	Revenue at existing rates	($Millions)			3,071.8
14.	Revenue requirement	($Millions)			3,153.8
15.	Gross revenue (deficiency)	($Millions)			(82.0)

Change in Revenue Requirement
2007 Test Year

Line No.		Col. 1 ADR Settlement Proposal	Col.2 Impact No.1 Filed: 2006-12-06 M1.T2.S5	Col.3 Change (Col.1-Col.2)
		($Millions)	($Millions)	($Millions)
	Cost of capital			
1.	Rate base	3,743.7	3,798.3	(54.6)
2.	Required rate of return	7.67%	7.63%	
3.	Cost of capital	287.1	289.8	(2.7)
	Cost of service			
4.	Gas costs	2,170.6	2,170.6	-
5.	Operation and maintenance	341.7	365.8	(24.1)
6.	Transition costs customer care	10.0	10.0	-
7.	Depreciation and amortization	227.1	254.6	(27.5)
8.	Fixed financing expense	1.3	1.3	-
9.	Notional utility account recovery	9.2	9.2	-
10.	Municipal and other taxes	45.9	47.6	(1.7)
11.	Cost of service	2,805.8	2,859.1	(53.3)
	Miscellaneous operating and non-operating income			
12.	Other operating revenue	(28.9)	(23.7)	(5.2)
13.	Interest and property rental	-	-	-
14.	Other income	(0.2)	(0.2)	-
15.	Misc. operating and non-operating income	(29.1)	(23.9)	(5.2)
	Income taxes on earnings			
16.	Excluding tax shield	119.2	107.2	12.0
17.	Tax shield provided by interest expense	(58.8)	(59.1)	0.3
18.	Income taxes on earnings	60.4	48.1	12.3
	Taxes on sufficiency / (deficiency)			
19.	Gross sufficiency / (deficiency)	(82.0)	(158.7)	76.7
20.	Net sufficiency / (deficiency)	(52.4)	(101.4)	49.0
21.	Income taxes on sufficiency / (deficiency)	29.6	57.3	(27.7)
22.	**Revenue requirement**	3,153.8	3,230.4	(76.6)
	Revenue at existing Rates			
23.	Gas sales	2,348.9	2,348.9	-
24.	Transportation service	720.9	720.9	-
25.	Transmission, compression and storage	1.9	1.9	-
26.	Sub-total	3,071.7	3,071.7	-
27.	Rounding adjustment	0.1	-	0.1
28.	Revenue at existing rates	3,071.8	3,071.7	0.1
29.	**Gross revenue sufficiency / (deficiency)**	(82.0)	(158.7)	76.7

APPENDIX "B"

TO INTERIM RATE ORDER

BOARD FILE NO. EB-2006-0034

DATED MARCH 26, 2007

Supporting Documentation

Documentation for Working Papers Supporting the EB-2006-0034 Interim Rate Order

The attached working papers provide support for the Rate Handbook filed as Appendix A to the Draft Interim Rate Order for January 1, 2007 interim rates. The Rate Handbook reflects the OEB approved EB-2006-0034 Settlement Agreement as filed at Exhibit N1, Tab 1, Schedule 1.

The rates shown in the Rate Handbook are designed to recover the revenue requirement stemming from the EB-2006-0034 Settlement Agreement and incorporate the July 1, 2006 (EB-2006-0099) rates as the base rates. The revenue deficiency as outlined in the Settlement Agreement is derived based on the following:

	($'000)	Reference
Revenue at Existing Rates	3,072.6	H2, Tab 2, Schedule 1 Including DPAC
Revenue Requirement	3,098.6	H2, Tab 2, Schedule 1 Including DPAC
Gross Revenue Deficiency	26.0	

The following sections have been changed or removed in the Rate Handbook and result from the EB-2006-0034 Settlement Agreement:

Issue	Location in Handbook
6.3 - Glossary of Terms	
Affiliated Gas Users	Page 1
Annual Contract Demand ("ACD")	Page 1
Authorized Volume	Page 1
Banked Gas Account	Page 1
Billing Contract Demand	Page 1
Billing Month	Page 1
Bundled Service	Page 1
Buy/Sell Price	Page 1
Contract Demand	Page 1
Curtailment Credit	Page 1
Daily Capacity Repurchase Quantity	Page 1
Customer Charge	Page 1
Daily Gas Quantity	Page 1
Demand Charge	Page 2
Direct Purchase	Page 2
Firm Service	Page 2
Firm Service Tendered ("FST")	Page 2
Firm Transportation ("FT")	Page 2
Gas Purchase Agreement	Page 2
Gas Sale Contract	Page 2
Gas Supply Load Balancing Charge	Page 2

Imperial Conversion Factors	Page 2
Large Volume Service Rates	Page 3
Large Volume Distribution Contract (“LVDC”)	Page 3
Large Volume Distribution Contract Rates	Page 3
Mean Daily Volume	Page 3
Metric Conversion Factors	Page 3
Minimum Annual Volume	Page 3
Nominate, Nomination	Page 3
Overrun Gas	Page 3
Rate Schedule	Page 3
Removal Permit	Page 3
Required Orders	Page 3
Sales Service	Page 3
Seasonal Credit	Page 3
System Sales Service	Page 3
Supply Overrun	Page 3
Transportation Service	Page 3
Unbundled Service	Page 3
Western Canada Buy Price	Page 3
In Franchise Services	Page 4
Direct Purchase Arrangements	Page 4
Western Canada	Page 4
Ontario Buy/Sell Arrangement	Page 4
Western Canada Buy/Sell	Page 4
Ontario Delivery T-Service Arrangements	Page 4
Minimum Bills	Page 5
Resale Prohibition	Page 6
Measurement	Page 6
Daily Delivered Volumes	Page 6
Authorized Overrun Gas	Page 6
Unauthorized Overrun Gas	Page 6
Offset of Banked Gas Accounts	Page 8
Disposition of Banked Gas Account Balances	Page 8

<u>Rate Schedules</u>

Unauthorized Overrun Gas Rate	Rates 100, 110, 115, 135, 145, 170, 200

The working papers are laid out as follows:

H2: Design of Rates using FACS shown at G2
G2: Fully Allocated Cost Study (FACS) using 2007 Board Approved methodology

<u>Description of H2 Exhibits</u>

The rates shown in the H2 exhibits are designed to recover the allocation of the revenue requirement based on the cost allocation methodology as approved in the EB-2006-0034 Settlement Agreement.

All exhibits in the H2 series follow the same format as in previous rate filings and rate orders and are listed below:

a) Tab 1, Schedule 1 of this exhibit summarizes, by rate class, and rate component, the revenues at existing and 2007 Interim rates found in EB-2006-0034. The forecast of billed revenues at 2006 July QRAM rates (Interim EB-2006-0099) is shown in columns 1 through 5. The revenues at the 2007 Interim rates are shown in columns 11 through 15. The net change in revenue, or the revenue deficiency/sufficiency, by component, is shown in columns 6 to 10. The total in column 10 indicates the forecast revenue deficiency that will be recovered from billed revenues. Schedule 2 displays the revenue requirement, unit rates and associated volumes by rate class and component.

b) The Tab 2 schedule summarizes the revenues shown in Schedule 1 and presents the unbilled revenues at current and 2007 Interim rates to yield calendar year revenues.

c) The schedule at Tab 3 compares the unit rates from EB-2006-0099 to the 2007 Interim unit rates.

d) Exhibits under Tab 4 show the derivation of gas supply commodity, gas supply load balancing rates and transportation rates from the cost allocated to the rate classes in the FACS which is found at Exhibit G2. The derivation of the Seasonal credits is found at page 3.

e) The schedules under Tab 5 show the detailed revenue calculations by rate class.

f) Annual bill comparisons indicating the impact of the 2007 Interim rates on typical customers relative to the July 1, 2006 rates are shown at Tab 7.

g) Tab 8 shows the derivation of the Rider E unit rates. The unit rates are derived by comparing the revenue at existing rates (EB-2006-0099) to the revenue at 2007 Interim rates. The revenues are based on the rates applied to the 2007 forecast volumes for the months of April to December 2007. This analysis can be found in pages 3 to 7 of Tab 8. Page 2 of Tab 8 derives the unit rates by component based on the change in revenue divided by the forecast volume. Page 1 is the determination of the unit rates based on the type of service.

DOCUMENTATION FOR WORKING PAPERS SUPPORTING THE SETTLEMENT PROPOSAL: EB-2006-0034

Description of Cost Allocation (G2) Exhibits

The G2 exhibits, also referred to as the Fully Allocated Cost Study (FACS), allocate the test year revenue requirement to the customer rate classes.

All G2 series exhibits have been updated for the Impact Statement No.1 (EB-2006-0034, Exhibit M1), which the Company filed with the Board on December 06, 2006, and the Settlement Proposal (EB-2006-0034, Exhibit N1), which the Board approved on January 29, 2007.

The cost of service total of $3,098.6 million shown at G2/T2/S1/P1/L4/C1 equals revenues at existing rates of $3,071.8 million (N1/T2/S2/P1/L8/C2), plus direct purchase revenues at existing rates of $0.9 million (H2/T2/S1/P1/L15/C4), plus a settled deficiency in the amount of $26.0 million (N1/T1/S1/P46/Item 9.1).

As outlined in the Settlement Proposal at Issue 9.1, the parties agree that the Company can adjust rates to recover a $26.0 million deficiency effective as of January 1, 2007.

In its original filing the Company requested a $167.8 million deficiency. The Impact Statement No. 1 and Settlement Proposal adjustments reduce the deficiency to $26.0 million as follows:

Original Deficiency	167.8
Adjustments to Net Investments	(30.4)
Adjustments to O&M and Storage Costs	(28.5)
Adjustments to Return and Taxes	(82.9)
Deficiency from the Settlement Proposal to be Recovered in Rates Effective Jan. 01, 2007	26.0

Notes:

1) Adjustments reflect total net adjustments in Tables 2, 3 and 4 below.

The adjustments to rate base, net investments and operating and maintenance (O&M) expenses reflect the specific impacts of settled issues. The adjustments to return and taxes reflect the impact on return and taxes from settled issues and also capture deficiency consequences from unsettled issues.

The following four tables illustrate how the adjustments were made in the FACS for both the Impact Statement No. 1 and the Settlement Proposal.

The adjustments are compared to the Company's original filing with respect to:

- rate base for plant, equipment and working capital allowance;
- net investments;
- O&M and storage costs; and
- return and taxes.

Table 1: Rate Base Adjustments to Plant, Equipment and Working Capital Allowance

#	Item	Impact Statement Adjustment	Settlement Proposal Adjustment	Net Adjustment	Reference
1.0	Distribution Plant(1)	0	(56.4)	(56.4)	G2/T3/S1/P1/L2/C1
2.0	General Plant	0	0	0	G2/T3/S1/P1/L3/C1
3.0	Working Capital Allow.(2)	(3.0)	1.8	(1.2)	G2/T3/S1/P1/L6/C1
4.0	Total	(3.0)	(54.6)	(57.6)	

Notes:

1) The impact on rate base and accumulated depreciation from the settlement of Issues 1.1 through 1.8 and Issue 3.11.

2) The impact on working capital allowance from the EB-2005-0551 NGEIR Decision to reflect cost-based storage rates for services acquired from Union Gas and from reduction to O&M expenses as per the Settlement Proposal.

Table 2: Adjustments to Net Investments

#	Item	Impact Statement Adjustment	Settlement Proposal Adjustment	Net Adjustment	Reference
1.1	Depreciation(1)	0	(27.5)	(27.5)	G2/T3/S3/P1/L1.1/C1
1.2	Other Taxes(2)	0	(1.7)	(1.7)	G2/T3/S3/P1/L1.2+1.3/C1
1.0	Total Investments	0	(29.2)	(29.2)	G2/T3/S3/P1/L1/C1
2.0	Misc. Revenues(3)	3.5	(4.7)	(1.2)	G2/T3/S3/P1/L2/C1
3.0	Total	3.5	(33.9)	(30.4)	

Notes:

1) The impact on depreciation and amortization from reduction in capital expenditures and from existing Board-approved depreciation rates as per the settlement of Issues 1.1 through 1.8 and Issue 3.11 respectively.

2) The impact on other taxes from $1.3 M reduction in municipal taxes and $0.4 M reduction in capital taxes as per the settlement of Issue 3.14 and Issues 1.1 through 1.8 respectively.

3) The impact on misc. revenues from transactional services' revenues and increases in other and NGV program revenues. Note that misc. revenues are shown as credits in G2 exhibits.

Table 3: Adjustments to Operating and Maintenance (O&M) and Storage Costs

#	Item	Impact Statement Adjustment	Settlement Proposal Adjustment	Net Adjustment	Reference
1.0	Storage with Union Gas(1)	(6.0)	0	(6.0)	G2/T6/S2/P2/L4.1+4.2/C3
2.0	DSM and other(2)	1.6	0	1.6	G2/T3/S4/P2/L4.10+4.11/C1
3.0	Utility O&M and Storage(3)	0	(24.1)	(24.1)	G2/T3/S4 & G2/T6+7/S2+3
4.0	Total	(4.4)	(24.1)	(28.5)	

Notes:

1) The impact on storage service with Union Gas from the EB-2005-0551 NGEIR Decision to reflect cost-based storage rates.

2) The impact on DSM from the EB-2006-0021 Decision to set DSM budget at $22.0 M, which required an increase of $1.7 M to the $20.3 M DSM budget embedded in the original filing. Includes a $0.1 M reduction in other O&M for which reference is not provided.

3) The impact on utility O&M and storage costs from the Settlement Proposal. These adjustments are reflected in exhibits G2/T3/S4/Items 2 through 8/C1 and G2/T6/S2/P2/L1.5+2.4 and G2/T7/S3/P1/L2.1+2.2+2.3.

Table 4: Adjustments to Return & Taxes

#	Item	Impact Statement Adjustment	Settlement Proposal Adjustment	Net Adjustment	Reference
1.0	Return & Taxes	(7.8)	(71.3)	(79.1)	G2/T5/S3/P1/L6/C3
2.0	Tecumseh Return & Taxes	(0.4)	(3.4)	(3.8)	G2/T7/S3/P1/L1
3.0	Total(1)	(8.2)	(74.7)	(82.9)	

Notes:

1) The impact on return and taxes from settled issues and deficiency consequences from unsettled issues.

The G2 exhibits provided in this filing follow the same format as in previous rate filings or rate orders:

a) Tab 2 exhibits provide a summary of the FACS' results. They outline the allocation of the proposed revenue requirement, return on the allocated rate base and the revenue to cost ratio by rate class.

b) Tab 3 exhibits functionalize rate base, working capital, net investment, and O&M costs into similar operating functions to facilitate identification of costs that are associated with a distinct aspect of the Company. The functionalization of costs allows for consistent treatment of similar costs.

c) Tab 4 exhibits classify the functionalized costs into categories that vary between rate classes by an identifiable factor or allocator. In this step the costs are classified to three general cost groups based on whether they vary with volumetric demands, peak demands, or other customer specific demands. The costs are further sub-classified within these three broad categories of classification when required.

d) Tab 5 exhibits allocate the classified cost to each rate class based on allocation factors that are referenced on the exhibits.

e) Tab 6 exhibits provide rate base, working capital and net investment functionalization factors, classify transportation and storage costs and gas costs to operations, and provide cost of service allocation factors and allocation percentages.

f) Tab 7 exhibits provide functionalization and classification of costs for Tecumseh Gas. These costs are then used to charge back storage costs to Enbridge Gas Distribution's in-franchise customers and to derive ex-franchise storage rates.

REVENUE COMPARISON - CURRENT METHODOLOGY vs PROPOSED METHODOLOGY BY RATE CLASS AND COMPONENT ($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	Col. 14	Col. 15
		REVENUE - EB-2006-0099 RATES					(SUFFICIENCY) / DEFICIENCY					REVENUE -INTERIM EB-2006-0034 RATES				
ITEM NO.	RATE NO.	DISTRIB'TN	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL	DISTRIB'TN	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL	DISTRIB'TN	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL
1.	1	614,841	170,812	51,178	939,358	1,776,189	34,174	(2,173)	(14,691)	1,078	18,388	649,015	168,639	36,486	940,436	1,794,577
2.	6	215,881	121,277	37,790	493,868	868,817	15,453	(1,525)	(11,472)	863	3,319	231,334	119,752	26,318	494,731	872,136
3.	9	727	273	6	1,835	2,842	75	(4)	(6)	0	65	802	270	0	1,836	2,907
4.	100	54,558	51,376	14,798	74,243	194,976	8,440	(673)	(5,463)	(15)	2,288	62,998	50,703	9,335	74,228	197,264
5.	110	11,517	22,981	2,394	16,981	53,872	1,255	(301)	(1,268)	2	(311)	12,772	22,680	1,126	16,983	53,561
6.	115	8,795	27,593	1,524	14,138	52,050	1,949	(440)	(1,145)	2	365	10,744	27,153	379	14,140	52,416
7.	125	1,220	0	0	0	1,220	76	0	0	0	76	1,296	0	0	0	1,296
8.	135	783	1,454	(434)	1,777	3,580	82	(27)	(33)	(6)	17	866	1,427	(467)	1,771	3,597
9.	145	4,637	9,305	547	14,013	28,503	793	(122)	(437)	(10)	225	5,430	9,183	111	14,003	28,728
10.	170	4,086	23,821	(6,623)	19,487	40,770	1,408	(354)	(679)	3	378	5,494	23,467	(7,303)	19,490	41,148
11.	200	2,152	5,580	1,190	40,366	49,288	824	(73)	(341)	5	416	2,976	5,507	849	40,371	49,704
12.	300	150	0	0	0	150 [1]	(40)	0	0	0	(40)	110	0	0	0	110 [2]
13.	SUB-TOTAL	919,347	434,474	102,370	1,616,066	3,072,257	64,490	(5,693)	(35,535)	1,922	25,184	983,837	428,781	66,834	1,617,988	3,097,441
14.	STORAGE	1,896	0	0	0	1,896	(241)	0	0	0	(241)	1,655	0	0	0	1,655
15.	DPAC	900	0	0	0	900	660	0	0	0	660	1,560	0	0	0	1,560
16.	TOTAL	922,143	434,474	102,370	1,616,066	3,075,053	64,909	(5,693)	(35,535)	1,922	25,603	987,052	428,781	66,834	1,617,988	3,100,656

Notes:
1. Revenue based on EB-2006-0099 Rates for Rate 305
2. Revenue based on EB-2006-0034 Rate 300 Interruptible Range Rate

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	4,476,300	649,015	14.50	4,476,300	168,639	3.77	4,476,300	36,486	0.82	2,757,004	940,436	34.11	1,794,577
2.	6	3,142,097	231,334	7.36	3,142,097	119,752	3.81	3,142,097	26,318	0.84	1,443,468	494,731	34.27	872,136
3.	9	7,375	802	10.87	7,375	270	3.66	7,375	0	0.00	5,409	1,836	33.94	2,907
4.	100	1,387,023	62,998	4.54	1,387,023	50,703	3.66	1,387,023	9,335	0.67	218,347	74,228	34.00	197,264
5.	110	620,429	12,772	2.06	620,429	22,680	3.66	620,429	1,126	0.18	50,038	16,983	33.94	53,561
6.	115	906,196	10,744	1.19	906,196	27,153	3.00	906,196	379	0.04	41,661	14,140	33.94	52,416
7.	125	0	1,296	0.00	0	0	0.00	0	0	0.00	0	0	0.00	1,296
8.	135	55,396	866	1.56	55,396	1,427	2.58	55,396	(467)	(0.84)	5,208	1,771	34.00	3,597
9.	145	251,217	5,430	2.16	251,217	9,183	3.66	251,217	111	0.04	41,142	14,003	34.04	28,728
10.	170	729,625	5,494	0.75	729,625	23,467	3.22	729,625	(7,303)	(1.00)	57,424	19,490	33.94	41,148
11.	200	150,658	2,976	1.98	150,658	5,507	3.66	150,658	849	0.56	118,949	40,371	33.94	49,704
12.	300	31,237	110	0.00	0	0	0.00	0	0	0.00	0	0	0.00	110
13	SUB-TOTAL	11,757,552	983,837	8.37	11,726,315	428,781	3.66	11,726,315	66,834	0.57	4,738,651	1,617,988	34.14	3,097,441
14.	STORAGE	N/A	1,655	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,655
15.	DPAC	N/A	1,560	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,560
16.	TOTAL	11,757,552	987,052	8.37	11,726,315	428,781	3.66	11,726,315	66,834	0.57	4,738,651	1,617,988	34.14	3,100,656

** Total Revenue includes T-Service

FISCAL YEAR REVENUE COMPARISON - CURRENT METHODOLOGY vs PROPOSED METHODOLOGY BY RATE CLASS

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
		EB-2006-0099			INTERIM EB-2006-0034			
Item No.	Rate No.	Revenue ($000)	Unbilled Revenue ($000)	Total ($000)	Proposed Revenue ($000)	Unbilled Revenue ($000)	Total ($000)	Total Difference ($000)
1.	1	1,776,189	1,038	1,777,227	1,794,577	1,054	1,795,631	18,404
2.	6	868,817	(3,556)	865,261	872,136	(3,558)	868,578	3,317
3.	9	2,842	0	2,842	2,907	0	2,907	65
4.	100	194,976	(0)	194,976	197,264	361	197,625	2,649
5.	110	53,872	(12)	53,860	53,561	(13)	53,547	(312)
6.	115	52,050	1	52,051	52,416	1	52,416	365
7.	125	1,220	0	1,220	1,296	0	1,296	76
8.	135	3,580	0	3,580	3,597	0	3,597	17
9.	145	28,503	0	28,503	28,728	56	28,784	281
10.	170	40,770	1	40,771	41,148	1	41,148	378
11.	200	49,288	0	49,288	49,704	0	49,704	416
12.	300	150	0	150	110	0	110	(40)
13.	SUB-TOTAL	3,072,257	(2,529)	3,069,728	3,097,441	(2,099)	3,095,342	25,614
14.	STORAGE	1,896	0	1,896	1,655	0	1,655	(241)
15.	DPAC	900	0	900	1,560	0	1,560	660
16.	TOTAL	3,075,053	(2,529)	3,072,524	3,100,656	(2,099)	3,098,557	26,033

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

Item No.	Rate No.	Col. 1	Col. 2 Rate Block m³	Col. 3 EB-2006-0099 cents *	Col. 4 Rate Change cents *	Col. 5 Interim EB-2006-0034 cents *
	RATE 1					
1.01		Customer Charge		$11.25	$0.63	$11.88
1.02		Delivery Charge	first 30	9.7581	0.5399	10.2979
1.03			next 55	9.1295	0.5051	9.6346
1.04			next 85	8.6369	0.4779	9.1148
1.05			over 170	8.2703	0.4576	8.7278
1.06		Gas Supply Load Balancing		1.1433	(0.3282)	0.8151
1.07		Gas Supply Transportation		3.8159	(0.0485)	3.7674
1.08		Gas Supply Commodity - System		34.0717	0.0391	34.1108
1.09		Gas Supply Commodity - Buy/Sell		34.0538	0.0385	34.0923
	RATE 6					
2.01		Customer Charge		$22.00	$1.58	$23.58
2.02		Delivery Charge	First 500	8.7165	0.6233	9.3398
2.03			Next 1050	6.6633	0.4765	7.1398
2.04			Next 4500	5.2260	0.3737	5.5997
2.05			Next 7000	4.3021	0.3076	4.6098
2.06			Next 15250	3.8915	0.2783	4.1697
2.07			Over 28300	3.7888	0.2709	4.0597
2.08		Gas Supply Load Balancing		1.2027	(0.3651)	0.8376
2.09		Gas Supply Transportation		3.8598	(0.0485)	3.8112
2.10		Gas Supply Commodity - System		34.2140	0.0598	34.2738
2.11		Gas Supply Commodity - Buy/Sell		34.1961	0.0591	34.2552
	RATE 9					
3.01		Customer Charge		$200.00	$20.55	$220.55
3.02		Delivery Charge	first 20000	9.0864	0.9337	10.0201
3.03			over 20000	8.5052	0.8739	9.3791
3.04		Gas Supply Load Balancing		0.0855	(0.0855)	0.0000
3.05		Gas Supply Transportation		3.7041	(0.0485)	3.6555
3.06		Gas Supply Commodity - System		33.9354	0.0044	33.9398
3.07		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212
	RATE 100					
4.01		Customer Charge		$100.00	$15.10	$115.10
4.02		Demand Charge (Cents/Month/m³)		-	8.0000	8.0000
4.03		Delivery Charge	first 14,000	5.0940	(0.2695)	4.8245
4.04			next 28,000	3.7350	(0.2695)	3.4655
4.05			over 42,000	3.1760	(0.2695)	2.9065
4.06		Gas Supply Load Balancing		1.0669	(0.3939)	0.6730
4.07		Gas Supply Transportation		3.7041	(0.0485)	3.6555
4.08		Gas Supply Commodity - System		34.0023	(0.0070)	33.9953
		Gas Supply Commodity - Buy/Sell		33.9843	(0.0075)	33.9768
	RATE 110					
5.01		Customer Charge		$500.00	$54.50	$554.50
5.02		Demand Charge (Cents/Month/m³)		20.0000	2.1800	22.1800
5.03		Delivery Charge	first 1,000,000	0.4569	0.0474	0.5044
5.04			over 1,000,000	0.3069	0.0474	0.3544
5.05		Load Balancing Commodity		0.3858	(0.2043)	0.1815
5.06		Gas Supply Transportation		3.7041	(0.0485)	3.6555
5.07		Gas Supply Commodity - System		33.9354	0.0044	33.9398
5.08		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212

NOTE : * Cents unless otherwise noted.

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2006-0099 cents *	Col. 4 Rate Change cents *	Col. 5 Interim EB-2006-0034 cents *
	RATE 115					
1.01		Customer Charge		$500.00	$110.78	$610.78
1.02		Demand Charge (Cents/Month/m³)		20.0000	4.4300	24.4300
1.03		Delivery Charge	first 1,000,000	0.2356	0.0374	0.2730
1.04			over 1,000,000	0.1356	0.0374	0.1730
1.05		Load Balancing Commodity		0.1682	(0.1264)	0.0418
1.06		Gas Supply Transportation		3.0449	(0.0485)	2.9964
1.07		Gas Supply Commodity - System		33.9354	0.0044	33.9398
1.08		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212
	RATE 125					
2.01		Customer Charge		0.0000	$ 500.00	$ 500.00
2.02		Delivery Charge (Cents/Month/m³ of Contract Dmnd)		8.3768	0.5249	8.9017
	RATE 135	DEC - MAR				
3.00		Customer Charge		$100.00	$10.53	$110.53
3.01		Delivery Charge	first 14,000	6.5082	0.1406	6.6488
3.02			next 28,000	5.3082	0.1406	5.4488
3.03			over 42,000	4.9082	0.1406	5.0488
3.04		Gas Supply Load Balancing		0.0604	(0.0604)	0.0000
3.05		Gas Supply Transportation		2.6243	(0.0485)	2.5757
3.06		Gas Supply Commodity - System		34.1155	(0.1132)	34.0023
3.07		Gas Supply Commodity - Buy/Sell		34.0976	(0.1139)	33.9837
	RATE 135	APR - NOV				
3.08		Customer Charge		$100.00	$10.53	$110.53
3.09		Delivery Charge	first 14,000	1.8082	0.1406	1.9488
3.10			next 28,000	1.1082	0.1406	1.2488
3.11			over 42,000	0.9082	0.1406	1.0488
3.12		Gas Supply Load Balancing		0.0604	(0.0604)	0.0000
3.13		Gas Supply Transportation		2.6243	(0.0485)	2.5757
3.14		Gas Supply Commodity - System		34.1155	(0.1132)	34.0023
3.15		Gas Supply Commodity - Buy/Sell		34.0976	(0.1139)	33.9837
	RATE 145					
4.00		Customer Charge		$100.00	$17.11	$117.11
4.01		Demand Charge (Cents/Month/m³)		-	8.0000	8.0000
4.02		Delivery Charge	first 14,000	3.3237	(0.4940)	2.8296
4.03			next 28,000	1.9647	(0.4940)	1.4706
4.04			over 42,000	1.4057	(0.4940)	0.9116
4.05		Gas Supply Load Balancing		0.5923	(0.1738)	0.4185
4.06		Gas Supply Transportation		3.7041	(0.0485)	3.6555
4.07		Gas Supply Commodity - System		34.0606	(0.0243)	34.0363
4.08		Gas Supply Commodity - Buy/Sell		34.0427	(0.0250)	34.0177
	RATE 170					
5.00		Customer Charge		$200.00	$68.95	$268.95
5.01		Demand Charge (Cents/Month/m³)		3.0000	1.0300	4.0300
5.02		Delivery Charge	first 1,000,000	0.4026	0.1087	0.5113
5.03			over 1,000,000	0.2026	0.1087	0.3113
5.04		Gas Supply Load Balancing		0.2977	(0.0931)	0.2046
5.05		Gas Supply Transportation		3.2648	(0.0485)	3.2163
5.06		Gas Supply Commodity - System		33.9354	0.0044	33.9398
5.07		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212

NOTE : * Cents unless otherwise noted.

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

		Col.1	Col. 2	Col. 3	Col. 4	Col. 5	
Item No.	Rate No.		Rate Block m³	EB-2006-0099 cents *	Rate Change cents *	Interim EB-2006-0034 cents *	
	RATE 200						
1.00		Customer Charge		$0.00	$0.00	$0.00	
1.01		Demand Charge (Cents/Month/m³)		10.0000	3.8300	13.8300	
1.02		Delivery Charge		0.6963	0.2666	0.9629	
1.03		Gas Supply Load Balancing		0.8713	(0.2261)	0.6452	
1.04		Gas Supply Transportation		3.7041	(0.0485)	3.6555	
1.05		Gas Supply Commodity - System		33.9354	0.0044	33.9398	
1.06		Gas Supply Commodity - Buy/Sell		33.9175	0.0037	33.9212	
	RATE 300	FIRM SERVICE					
2.00		Monthly Customer Charge		$500.00	$0.00	$500.00	
2.01		Demand Charge (Cents/Month/m³)		22.6710	1.3492	24.0202	
		INTERRUPTIBLE SERVICE					
2.02		Minimum Delivery Charge (Cents/Month/m³)		0.3630	(0.0118)	0.3512	
2.03		Maximum Delivery Charge (Cents/Month/m³)		0.8944	0.0532	0.9476	
	RATE 315						
		Monthly Customer Charge		$150.00	$0.00	$150.00	
3.00		Space Demand Chg (Cents/Month/m³)		0.0367	(0.0021)	0.0346	
3.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		11.9813	0.1169	12.0982	
3.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.5069	(0.0070)	0.4999	(1)
	RATE 320						
4.00		Backstop	All Gas Sold	37.7005	(0.0285)	37.6720	

NOTE : * Cents unless otherwise noted.

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

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2006-0099 cents *		Col. 4 Change cents *	Col. 5 Interim EB-2006-0034 cents *
	RATE 325						
		Transmission & Compression					
1.00		Demand Charge - ATV ($/Month/10³ m³)		0.1776		(0.0124)	0.1652
1.01		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		16.0517		(1.1183)	14.9334
1.02		Commodity Charge		1.7920		(0.3196)	1.4724
		Storage					
1.03		Demand Charge - ATV ($/Month/10*3 m³)		0.2131	(2)	(0.0196)	0.1935
1.04		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		19.3327	(2)	(1.7769)	17.5558
1.05		Commodity Charge		0.7320		(0.1503)	0.5817
		(2) Note: These are UNBUNDLED Rates					
	RATE 330	Storage Service - Firm					
		Demand Charge ($/Month/10³ m³ of ATV)					
2.00		Minimum		0.3907		(0.0320)	0.3587
2.01		Maximum		1.9535		(0.1599)	1.7936
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)					
2.02		Minimum		35.3844		(2.8952)	32.4892
2.03		Maximum		176.9221		(14.4760)	162.4461
		Commodity Charge					
2.04		Minimum		2.5240		(0.4699)	2.0541
2.05		Maximum		12.6200		($2.3494)	10.2706
		Storage Service - Interruptible					
		Demand Charge ($/Month/10³ m³ of ATV)					
2.06		Minimum		0.3907		(0.0320)	0.3587
2.07		Maximum		1.9535		(0.1599)	1.7936
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)					
2.08		Minimum		28.3075		(2.3162)	25.9914
2.09		Maximum		141.5377		($11.5808)	129.9569
		Commodity Charge					
2.10		Minimum		2.5240		(0.4699)	2.0541
2.11		Maximum		12.6200		(2.3494)	10.2706
		Storage Service - Off Peak					
		Commodity Charge					
2.12		Minimum		1.0527		(0.1585)	0.8942
2.13		Maximum		42.7418		(4.6343)	38.1075
	RATE 331	Tecumseh Transmission Service					
		Firm					
		Demand Charge ($/Month/10³ m³ of					
3.00		Maximum Contracted Daily Delivery)		3.3350		1.1430	4.4780
		Interruptible					
3.01		Commodity Charge ($/10³m³ of gas delivered)		0.1320		0.0450	0.1770

NOTE : * Cents unless otherwise noted.

CALCULATION OF GAS SUPPLY CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF GAS SUPPLY CHARGE												
	GAS SUPPLY COSTS ($000)												
1.1	Annual Commodity	1,605,938	934,354	489,194	1,833	73,998	16,958	14,119	1,765	13,943	19,461	40,312	G2 T5 S3 1.1
1.2	Bad Debt Commodity	9,700	4,715	4,821	-	121	-	-	3	40	-	-	G2 T5 S3 1.2
1.3	System Gas Fee	880	512	268	1	41	9	8	1	8	11	22	G2 T5 S3 1.1
1.4	Return on Rate Base - Working Cash	1,471	856	448	2	68	16	13	2	13	18	37	G2 T5 S2 1.1
1	Total Commodity Costs	1,617,989	940,437	494,731	1,836	74,228	16,983	14,140	1,771	14,003	19,490	40,371	
	VOLUMES (10^3 m^3)												
2.1	System and Buy/Sell Volumes	4,738,651	2,757,004	1,443,468	5,409	218,347	50,038	41,661	5,208	41,142	57,424	118,949	
2.2	System Volumes	4,738,651	2,757,004	1,443,468	5,409	218,347	50,038	41,661	5,208	41,142	57,424	118,949	
	GAS SUPPLY CHARGE SYSTEM (¢/m^3)												
3.1	Annual Commodity	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	1.1 / 2.1
3.2	Bad Debt Commodity	0.2047	0.1710	0.3340	-	0.0555	-	-	0.0624	0.0965	-	-	1.2 / 2.1
3.3	System Gas Fee	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	0.0186	1.3 / 2.2
3.4	Return on Rate Base - Working Cash	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	1.4 / 2.1
3	System Gas Supply Charge	34.1445	34.1108	34.2738	33.9398	33.9953	33.9398	33.9398	34.0023	34.0363	33.9398	33.9398	
	GAS SUPPLY CHARGE BUY/SELL(¢/m3)												
4.1	Annual Commodity	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	33.8902	1.1 / 2.1
4.2	Bad Debt Commodity	0.2047	0.1710	0.3340	-	0.0555	-	-	0.0624	0.0965	-	-	1.2 / 2.1
4.3	Return on Rate Base - Working Cash	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	0.0310	1.4 / 2.1
4	Buy/Sell Gas Supply Charge	34.1259	34.0923	34.2552	33.9212	33.9768	33.9212	33.9212	33.9837	34.0177	33.9212	33.9212	

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
			RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	REFERENCE
		TOTAL	1	6	9	100	110	115	135	145	170	200	
	DERIVATION OF LOAD BALANCING CHARGES												
	ANNUAL LOAD BALANCING COSTS ($000)												
5.1	Peak	17,498	8,618	6,381	-	2,124	128	18	-	-	-	229	G2 T5 S3 2.1
5.2	Seasonal	6,808	3,180	2,275	-	823	114	41	-	120	170	85	G2 T5 S3 2.2
5.3	Return on Rate Base - Gas in Inventory	52,855	24,688	17,664	-	6,388	884	320	-	931	1,322	658	G2 T5 S2 2.2
5	Total Load Balancing	77,161	36,486	26,319	-	9,334	1,126	379	-	1,051	1,493	972	
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,726,315	4,476,300	3,142,097	7,375	1,387,023	620,429	906,196	55,396	251,217	729,625	150,658	G2 T6 S3, 1.3
7	**ANNUAL LOAD BALANCING CHARGE (¢/m3)** Load Balancing		0.8151	0.8376	-	0.6730	0.1815	0.0418	-	0.4185	0.2046	0.6452	5.0 / 6
	DERIVATION OF TRANSPORTATION CHARGES												
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,726,315	4,476,300	3,142,097	7,375	1,387,023	620,429	906,196	55,396	251,217	729,625	150,658	G2 T6 S3, 1.3
7.1	EB-2005-0524 Transportation Charge (¢/m^3)		3.8159	3.8598	3.7041	3.7041	3.7041	3.0449	2.6243	3.7041	3.2648	3.7041	
7.2	Increase/(Decrease) in Unit Rate		(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	(0.0485)	
7	**PROPOSED TRANSPORTATION CHARGE (¢/m^3)**		3.7674	3.8112	3.6555	3.6555	3.6555	2.9964	2.5757	3.6555	3.2163	3.6555	

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

			Reference
RATE 135			
Seasonal Credits Applicable to Rate 135	**$**	**(467)**	G2T5S3 line 3.3
Annual Volume (103 m3)		55,396	
Mean Daily Volume (103 m3)		152	
Annual Seasonal Credits	$	(3.08)	
Payable from December to March	$	(0.77)	
RATE 145			
Seasonal Credits Applicable to Rate 145	**$**	**(940)**	G2T5S3 line 2.4
Annual Volume (103 m3)		251,217	
Mean Daily Volume (103 m3)			
16 Hours		406	
72 Hours		287	
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	$	(811.12)	
72 Hours	$	(129.36)	
RATE 170			
Seasonal Credits Applicable to Rate 170	**$**	**(8,795)**	G2T5S3 line 2.4
Annual Volume (103 m3)		729,625	
Mean Daily Volume (103 m3)		1,999	
Annual Seasonal Credits	$	(4.40)	
Payable from December to March	$	(1.10)	
RATE 200			
Seasonal Credits Applicable to Rate 200	**$**	**(123)**	G2T5S3 line 2.4
Annual Volume (103 m3)		10,217	
Mean Daily Volume (103 m3)		28	
Annual Seasonal Credits	$	(4.40)	
Payable from December to March	$	(1.10)	

DETAILED REVENUE CALCULATION — EB-2006-0099 vs EB-2006-0034

Item No.		Rate Block m³ (Col. 1)		Bills & Volumes 10³ m³ (Col. 2)	EB-2006-0099 Rate cents* (Col. 3)	EB-2006-0099 Revenues $000 (Col. 4)	Rate Change cents* (Col. 5)	Interim EB-2006-0034 Rate cents* (Col. 6)	Interim EB-2006-0034 Revenues $000 (Col. 7)
	RATE 1								
1.1	Customer Charge	Bills		20,055,803	$11.25	225,628	$0.63	$11.88	238,263
1.2	Delivery Charge	first	30	573,680	9.7581	55,980	0.5399	10.2979	59,077
1.3		next	55	838,570	9.1295	76,557	0.5051	9.6346	80,793
1.4		next	85	920,584	8.6369	79,510	0.4779	9.1148	83,909
1.5		over	170	2,143,465	8.2703	177,270	0.4576	8.7278	187,078
1.	Total Distribution Charge			4,476,300		614,946			649,121
2.1	Gas Supply Load Balancing			4,476,300	1.1433	51,178	(0.3282)	0.8151	36,486
2.2	Gas Supply Transportation			4,476,300	3.8159	170,812	(0.0485)	3.7674	168,639
3.1	Gas Supply Commodity - System			2,757,004	34.0717	939,358	0.0391	34.1108	940,436
3.2	Gas Supply Commodity - Buy/Sell			0	34.0538	0	0.0385	34.0923	0
3.	Total Gas Supply Charge			2,757,004		939,358			940,436
4.1	TOTAL DISTRIBUTION			4,476,300		614,946			649,121
4.2	TOTAL GAS SUPPLY LOAD BALANCINC			4,476,300		221,990			205,126
4.3	TOTAL GAS SUPPLY COMMODITY			2,757,004		939,358			940,436
4.	TOTAL RATE 1			**4,476,300**		1,776,294			1,794,682
5.	Adj. Factor		0.9999						
6.	ADJUSTED REVENUE					**1,776,189**			**1,794,577**
7.	REVENUE INC./(DEC.)								**18,388**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION   EB-2006-0099 vs EB-2006-0034

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
				EB-2006-0099			Interim EB-2006-0034	
Item No.		Rate Block m³	Bills & Volumes 10³ m³	Rate cents*	Revenues $000	Rate Change cents*	Rate cents*	Revenues $000
	RATE 6							
1.1	Customer Charge	Bills	1,791,821	$22.00	39,420	$1.58	$23.58	42,251
1.2	Delivery Charge	First 500	498,786	8.7165	43,476	0.6233	9.3398	46,585
1.3		Next 1050	569,298	6.6633	37,934	0.4765	7.1398	40,647
1.4		Next 4500	938,975	5.2260	49,071	0.3737	5.5997	52,580
1.5		Next 7000	516,778	4.3021	22,232	0.3076	4.6098	23,822
1.6		Next 15250	364,527	3.8915	14,185	0.2783	4.1697	15,200
1.7		Over 28300	253,733	3.7888	9,613	0.2709	4.0597	10,301
1.	Total Distribution Charge		3,142,097		215,933			231,386
2.1	Gas Supply Load Balancing		3,142,097	1.2027	37,790	(0.3651)	0.8376	26,318
2.2	Gas Supply Transportation		3,142,097	3.8598	121,277	(0.0485)	3.8112	119,752
3.1	Gas Supply Commodity - System		1,443,468	34.2140	493,868	0.0598	34.2738	494,731
3.2	Gas Supply Commodity - Buy/Sell		0	34.1961	0	0.0591	34.2552	0
3.	Total Gas Supply Charge		1,443,468		493,868			494,731
4.1	TOTAL DISTRIBUTION		3,142,097		215,933			231,386
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		3,142,097		159,067			146,070
4.3	TOTAL GAS SUPPLY COMMODITY		1,443,468		493,868			494,731
4.	TOTAL RATE 6		**3,142,097**		868,868			872,187
5.	Adj. Factor	1.000						
6.	ADJUSTED REVENUE				**868,817**			**872,136**
7.	REVENUE INC./(DEC.)							**3,319**

NOTE * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION EB-2006-0099 vs EB-2006-0034

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
							Interim	
Item			Bills &	EB-2006-0099		Rate	EB-2006-0034	
No.		Rate Block	Volumes	Rate	Revenues	Change	Rate	Revenues
		m³	10³ m³	cents*	$000	cents*	cents*	$000
	RATE 9							
1.1	Customer Charge	Bills	384	$200.00	77	$20.55	$220.55	85
1.2	Delivery Charge	first 20000	3,945	9.0864	358	0.9337	10.0201	395
1.3		over 20000	3,430	8.5052	292	0.8739	9.3791	322
1.	Total Distribution Charge		7,375		727			802
2.1	Gas Supply Load Balancing		7,375	0.0855	6	(0.0855)	0.0000	0
2.2	Gas Supply Transportation		7,375	3.7041	273	(0.0485)	3.6555	270
3.1	Gas Supply Commodity - System		5,409	33.9354	1,835	0.0044	33.9398	1,836
3.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
3.	Total Gas Supply Charge		5,409		1,835			1,836
4.1	TOTAL DISTRIBUTION		7,375		727			802
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		7,375		279			270
4.3	TOTAL GAS SUPPLY COMMODITY		5,409		1,835			1,836
4	TOTAL RATE 9		**7,375**		**2,842**			**2,907**
5.	REVENUE INC./(DEC.)							**65**

							Interim	
			Contracts &	EB-2006-0099		Rate	EB-2006-0034	
		Rate Block	Volumes	Rate	Revenues	Change	Rate	Revenues
		m³	10³ m³	cents*	$000	cents*	cents*	$000
	RATE 100							
1.1	Customer Charge	Contracts	23,340	$100.00	2,334	$15.10	$115.10	2,686
1.2	Demand Charge		147,823	$0.00	0	8.00	8.00	11,826
1.3	Delivery Charge	first 14,000	301,761	5.0940	15,372	(0.2695)	4.8245	14,558
1.4		next 28,000	426,590	3.7350	15,933	(0.2695)	3.4655	14,783
1.5		over 42,000	658,672	3.1760	20,919	(0.2695)	2.9065	19,144
1	Total Distribution Charge		1,387,023		54,558			62,998
2.1	Gas Supply Load Balancing		1,387,023	1.0669	14,798	(0.3939)	0.6730	9,335
2.2	Gas Supply Transportation		1,387,023	3.7041	51,376	(0.0485)	3.6555	50,703
3.1	Gas Supply Commodity - System		218,347	34.0023	74,243	(0.0070)	33.9953	74,228
3.2	Gas Supply Commodity - Buy/Sell		0	33.9843	0	(0.0075)	33.9768	0
3	Total Gas Supply Charge		218,347		74,243			74,228
4.1	TOTAL DISTRIBUTION		1,387,023		54,558			62,998
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		1,387,023		66,174			60,038
4.3	TOTAL GAS SUPPLY COMMODITY		218,347		74,243			74,228
4	TOTAL RATE 100		**1,387,023**		**194,976**			**197,264**
5	REVENUE INC./(DEC.)							**2,288**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION — EB-2006-0099 vs EB-2006-0034

Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
	RATE 110							
1.1	Customer Charge	Contracts	3,264	$500.00	1,632	$54.50	$554.50	1,810
1.2	Demand Charge		35,929	20.0000	7,186	2.1800	22.1800	7,969
1.3	Delivery Charge	first 1,000,000	529,548	0.4569	2,420	0.0474	0.5044	2,671
1.4		over 1,000,000	90,881	0.3069	279	0.0474	0.3544	322
1.	Total Distribution Charge		620,429		11,516			12,772
2.1	Load Balancing Demand		35,929	0.0000	0	0.0000	0.0000	0
2.2	Load Balancing Commodity		620,429	0.3858	2,394	(0.2043)	0.1815	1,126
2.3	Gas Supply Transportation		620,429	3.7041	22,981	(0.0485)	3.6555	22,680
2.	Total Gas Supply Load Balancing				25,375			23,806
3.1	Gas Supply Commodity - System		50,038	33.9354	16,981	0.0044	33.9398	16,983
3.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
3.	Total Gas Supply Charge		50,038		16,981			16,983
4.1	TOTAL DISTRIBUTION		620,429		11,516			12,772
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		620,429		25,375			23,806
4.3	TOTAL GAS SUPPLY COMMODITY		50,038		16,981			16,983
4.	TOTAL RATE 110		**620,429**		**53,872**			**53,561**
5.	REVENUE INC./(DEC.)							**(311)**

Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 115							
6.6	Customer Charge	Contracts	608	$500.00	304	$110.78	$610.78	371
6.2	Demand Charge		34,811	20.0000	6,962	4.4300	24.4300	8,504
6.3	Delivery Charge	first 1,000,000	300,110	0.2356	707	0.0374	0.2730	819
6.4		over 1,000,000	606,085	0.1356	822	0.0374	0.1730	1,049
6	Total Distribution Charge		906,196		8,795			10,744
7.1	Load Balancing Demand		34,811	0.0000	0	0.0000	0.0000	0
7.7	Load Balancing Commodity		906,196	0.1682	1,524	(0.1264)	0.0418	379
7.3	Gas Supply Transportation		906,196	3.0449	27,593	(0.0485)	2.9964	27,153
7	Total Gas Supply Load Balancing				29,117			27,532
8.1	Gas Supply Commodity - System		41,661	33.9354	14,138	0.0044	33.9398	14,140
8.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
8.	Total Gas Supply Charge		41,661		14,138			14,140
9.1	TOTAL DISTRIBUTION		906,196		8,795			10,744
9.2	TOTAL GAS SUPPLY LOAD BALANCIN		906,196		29,117			27,532
9.3	TOTAL GAS SUPPLY COMMODITY		41,661		14,138			14,140
9.	TOTAL RATE 115		**906,196**		**52,050**			**52,415**
10.	REVENUE INC./(DEC.)							**365**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION — EB-2006-0099 vs EB-2006-0034

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Item No.		Rate Block m³	Contracts & Volumes 10³ m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 125							
1.1	Customer Charge		5	$ -	0	$ 500.00	$ 500.00	3
1.2	Demand Charge		14,560	8.3768	1,220	0.5249	8.9017	1,296
1.	Total Distribution Charge		14,560		1,220			1,296

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Item No.		Rate Block m³	Contracts & Volumes 10³ m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 135							
	DEC to MAR							
1.1	Customer Charge	Contracts	144	$100.00	14	$10.53	$110.53	16
1.2	Delivery Charge	first 14,000	615	6.5082	40	0.1406	6.6488	41
1.3		next 28,000	996	5.3082	53	0.1406	5.4488	54
1.4		over 42,000	2,741	4.9082	135	0.1406	5.0488	138
1.	Total Distribution Charge		4,352		242			249
2.1	Gas Supply Load Balancing		4,352	0.0604	3	(0.0604)	0.0000	0
2.2	Gas Supply Transportation		4,352	2.6243	114	(0.0485)	2.5757	112
2.3	Seasonal Credit				(467)			(467)
3.1	Gas Supply Commodity - System		134	34.1155	46	(0.1132)	34.0023	46
3.2	Gas Supply Commodity - Buy/Sell		0	34.0976	0	(0.1139)	33.9837	0
3.	Total Gas Supply Charge		134		46			46
4.	SUB-TOTAL WINTER				-63			-60
	APR to NOV							
5.1	Customer Charge	Contracts	288	$100.00	29	$10.53	$110.53	32
5.2	Delivery Charge	first 14,000	3,812	1.8082	69	0.1406	1.9488	74
5.3		next 28,000	7,370	1.1082	82	0.1406	1.2488	92
5.4		over 42,000	39,861	0.9082	362	0.1406	1.0488	418
5.	Total Distribution Charge		51,044		541			616
6.1	Gas Supply Load Balancing		51,044	0.0604	31	(0.0604)	0.0000	0
6.2	Gas Supply Transportation		51,044	2.6243	1,340	(0.0485)	2.5757	1,315
7.1	Gas Supply Commodity - System		5,074	34.1155	1,731	(0.1132)	34.0023	1,725
7.2	Gas Supply Commodity - Buy/Sell		0	34.0976	0	(0.1139)	33.9837	0
7.	Total Gas Supply Charge		5,074		1,731			1,725
8.	SUB-TOTAL SUMMER				3,643			3,656
9.1	TOTAL DISTRIBUTION		55,396		783			866
9.2	TOTAL GAS SUPPLY LOAD BALANCINC		55,396		1,020			960
9.3	TOTAL GAS SUPPLY COMMODITY		5,208		1,777			1,771
9.	TOTAL RATE 135		**55,396**		**3,580**			**3,597**
10.	REVENUE INC./(DEC.)							**17**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION — EB-2006-0099 vs EB-2006-0034

Item No.		Col. 1 Rate Block m³	Col. 2 Contracts & Volumes 10^3 m³	Col. 3 EB-2006-0099 Rate cents*	Col. 4 EB-2006-0099 Revenues $000	Col. 5 Rate Change cents*	Col. 6 Interim EB-2006-0034 Rate cents*	Col. 7 Interim EB-2006-0034 Revenues $000
	RATE 145							
1.1	Customer Charge	Contracts	2,316	$100.00	232	$17.11	$117.11	271
1.2	Demand Charge		24,934	-	0	8.00	8.0000	1,995
1.2	Delivery Charge	first 14,000	30,526	3.3237	1,015	(0.4940)	2.8296	864
1.3		next 28,000	51,632	1.9647	1,014	(0.4940)	1.4706	759
1.4		over 42,000	169,059	1.4057	2,376	(0.4940)	0.9116	1,541
1.	Total Distribution Charge		251,217		4,637			5,430
2.1	Gas Supply Load Balancing		251,217	0.5923	1,488	(0.1738)	0.4185	1,051
2.2	Gas Supply Transportation		251,217	3.7041	9,305	(0.0485)	3.6555	9,183
2.3	Curtailment Credit				(940)			(940)
3.1	Gas Supply Commodity - System		41,142	34.0606	14,013	(0.0243)	34.0363	14,003
3.2	Gas Supply Commodity - Buy/Sell		0	34.0427	0	(0.0250)	34.0177	0
3.	Total Gas Supply Charge		41,142		14,013			14,003
4.1	TOTAL DISTRIBUTION		251,217		4,637			5,430
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		251,217		9,853			9,294
4.3	TOTAL GAS SUPPLY COMMODITY		41,142		14,013			14,003
4.	TOTAL RATE 145		**251,217**		**28,503**			**28,728**
5.	REVENUE INC./(DEC.)							**225**

		Rate Block m³	Contracts & Volumes 10^3 m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 170							
6.6	Customer Charge	Contracts	522	$200.00	104	$68.95	$268.95	140
6.2	Demand Charge		56,003	3.0000	1,680	1.0300	4.0300	2,257
6.3	Delivery Charge	first 1,000,000	411,401	0.4026	1,656	0.1087	0.5113	2,104
6.4		over 1,000,000	318,224	0.2026	645	0.1087	0.3113	991
6	Total Distribution Charge		729,625		4,086			5,492
7.1	Gas Supply Load Balancing		729,625	0.2977	2,172	(0.0931)	0.2046	1,493
7.7	Gas Supply Transportation		729,625	3.2648	23,821	(0.0485)	3.2163	23,467
7.3	Curtailment Credit				(8,795)			(8,795)
8.1	Gas Supply Commodity - System		57,424	33.9354	19,487	0.0044	33.9398	19,490
8.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
8.	Total Gas Supply Charge		57,424		19,487			19,490
9.1	TOTAL DISTRIBUTION		729,625		4,086			5,492
9.2	TOTAL GAS SUPPLY LOAD BALANCIN		729,625		17,198			16,164
9.3	TOTAL GAS SUPPLY COMMODITY		57,424		19,487			19,490
9.	TOTAL RATE 170		**729,625**		**40,770**			**41,145**
10.	REVENUE INC./(DEC.)							**375**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION EB-2006-0099 vs EB-2006-0034

Item No.		Col. 1 Rate Block m³	Col. 2 Contracts & Volumes 10³ m³	Col. 3 EB-2006-0099 Rate cents*	Col. 4 EB-2006-0099 Revenues $000	Col. 5 Rate Change cents*	Col. 6 Interim EB-2006-0034 Rate cents*	Col. 7 Interim EB-2006-0034 Revenues $000
	RATE 200							
1.1	Customer Charge	Contracts	12	$0.00	0	$0.00	$0.00	0
1.2	Demand Charge		11,032	10.0000	1,103	3.8300	13.8300	1,526
1.3	Delivery Charge		150,658	0.6963	1,049	0.2666	0.9629	1,451
1.	Total Distribution Charge		150,658		2,152			2,976
2.1	Gas Supply Load Balancing		150,658	0.8713	1,313	(0.2261)	0.6452	972
2.2	Gas Supply Transportation		150,658	3.7041	5,580	(0.0485)	3.6555	5,507
2.3	Curtailment Credit				(123)			(123)
3.1	Gas Supply Commodity - System		118,949	33.9354	40,366	0.0044	33.9398	40,371
3.2	Gas Supply Commodity - Buy/Sell		0	33.9175	0	0.0037	33.9212	0
3.	Total Gas Supply Charge		118,949		40,366			40,371
4.1	TOTAL DISTRIBUTION		150,658		2,152			2,976
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		150,658		6,770			6,356
4.3	TOTAL GAS SUPPLY COMMODITY		118,949		40,366			40,371
4.	TOTAL RATE 200		**150,658**		**49,288**			**49,704**
5.	REVENUE INC./(DEC.)							**416**

Item No.		Rate Block m³	Contracts & Volumes 10³ m³	EB-2006-0099 Rate cents*	EB-2006-0099 Revenues $000	Rate Change cents*	Interim EB-2006-0034 Rate cents*	Interim EB-2006-0034 Revenues $000
	RATE 300							
	Firm							
	Customer Charge		0		0	500.0000	$500.00	0
	Demand Charge		0		0	24.0202	24.0202	0
	Interruptible							
	Minimum Delivery Charge		31,237		150 [1]	0.3512	0.3512	110
	Maximum Delivery Charge		0		0	0.9476	0.9476	0
8.	TOTAL RATE 300 CDS		**0**		**150**			**110**
9.	REVENUE INC./(DEC.)							**(40)**

NOTE: * Cents unless otherwise noted.
1. Existing Rate 300 revenue is calculated using 2006 July QRAM Rate 305

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 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.	$	142.56	135.00	7.56	5.6%	142.56	135.00	7.56	5.6%
1.3	DISTRIBUTION CHG.	$	281.41	266.66	14.75	5.5%	424.20	401.94	22.26	5.5%
1.4	LOAD BALANCING	§ $	140.39	151.93	(11.54)	-7.6%	214.96	232.63	(17.67)	-7.6%
1.5	SALES COMMDTY	$	1,045.16	1,043.95	1.21	0.1%	1,600.14	1,598.30	1.84	0.1%
1.6	TOTAL SALES	$	1,609.52	1,597.54	11.98	0.7%	2,381.86	2,367.87	13.99	0.6%
1.7	TOTAL T-SERVICE	$	564.36	553.59	10.77	1.9%	781.72	769.57	12.15	1.6%
1.8	SALES UNIT RATE	$/m³	0.5253	0.5214	0.0039	0.7%	0.5078	0.5048	0.0030	0.6%
1.9	T-SERVICE UNIT RATE	$/m³	0.1842	0.1807	0.0035	1.9%	0.1666	0.1641	0.0026	1.6%
1.10	SALES UNIT RATE	$/GJ	13.937	13.834	0.1037	0.7%	13.472	13.393	0.0791	0.6%
1.11	T-SERVICE UNIT RATE	$/GJ	4.887	4.794	0.0933	1.9%	4.421	4.353	0.0687	1.6%

			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.	$	142.56	135.00	7.56	5.6%	142.56	135.00	7.56	5.6%
2.3	DISTRIBUTION CHG.	$	180.50	171.03	9.47	5.5%	187.85	177.98	9.87	5.5%
2.4	LOAD BALANCING	§ $	89.59	96.95	(7.36)	-7.6%	91.87	99.43	(7.56)	-7.6%
2.5	SALES COMMDTY	$	666.87	666.09	0.78	0.1%	683.92	683.13	0.79	0.1%
2.6	TOTAL SALES	$	1,079.52	1,069.07	10.45	1.0%	1,106.20	1,095.54	10.66	1.0%
2.7	TOTAL T-SERVICE	$	412.65	402.98	9.67	2.4%	422.28	412.41	9.87	2.4%
2.8	SALES UNIT RATE	$/m³	0.5522	0.5468	0.0053	1.0%	0.5517	0.5464	0.0053	1.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.2111	0.2061	0.0049	2.4%	0.2106	0.2057	0.0049	2.4%
2.10	SALES UNIT RATE	$/GJ	14.651	14.509	0.1418	1.0%	14.638	14.497	0.1411	1.0%
2.11	T-SERVICE UNIT RATE	$/GJ	5.600	5.469	0.1312	2.4%	5.588	5.457	0.1306	2.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	142.56	135.00	7.56	5.6%	142.56	135.00	7.56	5.6%
3.3	DISTRIBUTION CHG.	$	456.23	432.24	23.99	5.6%	106.06	100.50	5.56	5.5%
3.4	LOAD BALANCING	§ $	231.33	250.36	(19.03)	-7.6%	49.55	53.61	(4.06)	-7.6%
3.5	SALES COMMDTY	$	1,721.90	1,719.95	1.95	0.1%	368.74	368.31	0.43	0.1%
3.6	TOTAL SALES	$	2,552.02	2,537.55	14.47	0.6%	666.91	657.42	9.49	1.4%
3.7	TOTAL T-SERVICE	$	830.12	817.60	12.52	1.5%	298.17	289.11	9.06	3.1%
3.8	SALES UNIT RATE	$/m³	0.5056	0.5027	0.0029	0.6%	0.6169	0.6082	0.0088	1.4%
3.9	T-SERVICE UNIT RATE	$/m³	0.1644	0.1620	0.0025	1.5%	0.2758	0.2674	0.0084	3.1%
3.10	SALES UNIT RATE	$/GJ	13.413	13.337	0.0761	0.6%	16.369	16.136	0.2329	1.4%
3.11	T-SERVICE UNIT RATE	$/GJ	4.363	4.297	0.0658	1.5%	7.318	7.096	0.2224	3.1%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				Com. Htg., Air Cond'ng & Other Uses			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	282.96	264.00	18.96	7.2%	282.96	264.00	18.96	7.2%
1.3	DISTRIBUTION CHG.	$	1,597.92	1,491.16	106.76	7.2%	2,050.21	1,913.24	136.97	7.2%
1.4	LOAD BALANCING	§ $	1,050.91	1,144.41	(93.50)	-8.2%	1,361.09	1,482.19	(121.10)	-8.2%
1.5	SALES COMMDTY	$	7,747.94	7,734.42	13.52	0.2%	10,034.67	10,017.15	17.52	0.2%
1.6	TOTAL SALES	$	10,679.73	10,633.99	45.74	0.4%	13,728.93	13,676.58	52.35	0.4%
1.7	TOTAL T-SERVICE	$	2,931.79	2,899.57	32.22	1.1%	3,694.26	3,659.43	34.83	1.0%
1.8	SALES UNIT RATE	$/m³	0.4724	0.4704	0.0020	0.4%	0.4689	0.4671	0.0018	0.4%
1.9	T-SERVICE UNIT RATE	$/m³	0.1297	0.1283	0.0014	1.1%	0.1262	0.1250	0.0012	1.0%
1.10	SALES UNIT RATE	$/GJ	12.535	12.481	0.0537	0.4%	12.441	12.394	0.0474	0.4%
1.11	T-SERVICE UNIT RATE	$/GJ	3.441	3.403	0.0378	1.1%	3.348	3.316	0.0316	1.0%

			Medium Commercial Customer				Large Commercial Customer			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	282.96	264.00	18.96	7.2%	282.96	264.00	18.96	7.2%
2.3	DISTRIBUTION CHG.	$	8,605.13	8,030.38	574.75	7.2%	15,755.58	14,703.30	1,052.28	7.2%
2.4	LOAD BALANCING	§ $	7,882.67	8,584.06	(701.39)	-8.2%	15,765.29	17,168.06	(1,402.77)	-8.2%
2.5	SALES COMMDTY	$	58,115.68	58,014.31	101.37	0.2%	116,231.02	116,028.24	202.78	0.2%
2.6	TOTAL SALES	$	74,886.44	74,892.75	(6.31)	0.0%	148,034.85	148,163.60	(128.75)	-0.1%
2.7	TOTAL T-SERVICE	$	16,770.76	16,878.44	(107.68)	-0.6%	31,803.83	32,135.36	(331.53)	-1.0%
2.8	SALES UNIT RATE	$/m³	0.4416	0.4417	(0.0000)	0.0%	0.4365	0.4369	(0.0004)	-0.1%
2.9	T-SERVICE UNIT RATE	$/m³	0.0989	0.0995	(0.0006)	-0.6%	0.0938	0.0948	(0.0010)	-1.0%
2.10	SALES UNIT RATE	$/GJ	11.718	11.719	(0.0010)	0.0%	11.582	11.592	(0.0101)	-0.1%
2.11	T-SERVICE UNIT RATE	$/GJ	2.624	2.641	(0.0168)	-0.6%	2.488	2.514	(0.0259)	-1.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 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.	$	282.96	264.00	18.96	7.2%	282.96	264.00	18.96	7.2%
3.3	DISTRIBUTION CHG.	$	2,832.89	2,643.66	189.23	7.2%	3,799.49	3,545.72	253.77	7.2%
3.4	LOAD BALANCING	§ $	2,012.23	2,191.27	(179.04)	-8.2%	2,970.73	3,235.07	(264.34)	-8.2%
3.5	SALES COMMDTY	$	14,835.42	14,809.52	25.90	0.2%	21,901.98	21,863.79	38.19	0.2%
3.6	TOTAL SALES	$	19,963.50	19,908.45	55.05	0.3%	28,955.16	28,908.58	46.58	0.2%
3.7	TOTAL T-SERVICE	$	5,128.08	5,098.93	29.15	0.6%	7,053.18	7,044.79	8.39	0.1%
3.8	SALES UNIT RATE	$/m³	0.4612	0.4599	0.0013	0.3%	0.4531	0.4524	0.0007	0.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.1185	0.1178	0.0007	0.6%	0.1104	0.1102	0.0001	0.1%
3.10	SALES UNIT RATE	$/GJ	12.237	12.203	0.0337	0.3%	12.022	12.003	0.0193	0.2%
3.11	T-SERVICE UNIT RATE	$/GJ	3.143	3.125	0.0179	0.6%	2.928	2.925	0.0035	0.1%

			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.	$	282.96	264.00	18.96	7.2%	282.96	264.00	18.96	7.2%
4.3	DISTRIBUTION CHG.	$	8,812.11	8,223.60	588.51	7.2%	15,909.36	14,846.84	1,062.52	7.2%
4.4	LOAD BALANCING	§ $	7,882.69	8,584.06	(701.37)	-8.2%	15,765.24	17,168.01	(1,402.77)	-8.2%
4.5	SALES COMMDTY	$	58,115.69	58,014.29	101.40	0.2%	116,230.69	116,027.89	202.80	0.2%
4.6	TOTAL SALES	$	75,093.45	75,085.95	7.50	0.0%	148,188.25	148,306.74	(118.49)	-0.1%
4.7	TOTAL T-SERVICE	$	16,977.76	17,071.66	(93.90)	-0.6%	31,957.56	32,278.85	(321.29)	-1.0%
4.8	SALES UNIT RATE	$/m³	0.4429	0.4428	0.0000	0.0%	0.4370	0.4373	(0.0003)	-0.1%
4.9	T-SERVICE UNIT RATE	$/m³	0.1001	0.1007	(0.0006)	-0.6%	0.0942	0.0952	(0.0009)	-1.0%
4.10	SALES UNIT RATE	$/GJ	11.750	11.749	0.0012	0.0%	11.594	11.603	(0.0093)	-0.1%
4.11	T-SERVICE UNIT RATE	$/GJ	2.657	2.671	(0.0147)	-0.6%	2.500	2.525	(0.0251)	-1.0%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				**Rate 100 - Average Commercial Firm**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
1.2	CUSTOMER CHG.	$	1,381.20	1,200.00	181.20	15.1%	1,381.20	1,200.00	181.20	15.1%
1.3	DISTRIBUTION CHG.	$	16,548.04	14,588.90	1,959.14	13.4%	26,163.16	23,466.91	2,696.25	11.5%
1.4	LOAD BALANCING	$	14,681.81	16,182.56	(1,500.75)	-9.3%	25,909.14	28,557.46	(2,648.33)	-9.3%
1.5	SALES COMMDTY	$	115,307.98	115,331.72	(23.74)	0.0%	203,484.98	203,526.88	(41.90)	0.0%
1.6	TOTAL SALES	$	147,919.03	147,303.18	615.85	0.4%	256,938.48	256,751.25	187.22	0.1%
1.7	TOTAL T-SERVICE	$	32,611.05	31,971.46	639.59	2.0%	53,453.50	53,224.37	229.12	0.4%
1.8	SALES UNIT RATE	$/m³	0.4361	0.4343	0.0018	0.4%	0.4293	0.4289	0.0003	0.1%
1.9	T-SERVICE UNIT RATE	$/m³	0.0961	0.0943	0.0019	2.0%	0.0893	0.0889	0.0004	0.4%
1.10	SALES UNIT RATE	$/GJ	11.571	11.522	0.0482	0.4%	11.389	11.381	0.0083	0.1%
1.11	T-SERVICE UNIT RATE	$/GJ	2.551	2.501	0.0500	2.0%	2.369	2.359	0.0102	0.4%
			Rate 100 - Small Industrial Firm				**Rate 100 - Average Industrial Firm**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
2.2	CUSTOMER CHG.	$	1,381.20	1,200.00	181.20	15.1%	1,381.20	1,200.00	181.20	15.1%
2.3	DISTRIBUTION CHG.	$	16,820.85	14,861.70	1,959.15	13.2%	26,404.57	23,708.35	2,696.22	11.4%
2.4	LOAD BALANCING	$	14,681.82	16,182.54	(1,500.72)	-9.3%	25,909.10	28,557.43	(2,648.33)	-9.3%
2.5	SALES COMMDTY	$	115,307.98	115,331.72	(23.74)	0.0%	203,484.63	203,526.55	(41.92)	0.0%
2.6	TOTAL SALES	$	148,191.85	147,575.96	615.89	0.4%	257,179.50	256,992.33	187.17	0.1%
2.7	TOTAL T-SERVICE	$	32,883.87	32,244.24	639.63	2.0%	53,694.87	53,465.78	229.09	0.4%
2.8	SALES UNIT RATE	$/m³	0.4369	0.4351	0.0018	0.4%	0.4297	0.4293	0.0003	0.1%
2.9	T-SERVICE UNIT RATE	$/m³	0.0969	0.0951	0.0019	2.0%	0.0897	0.0893	0.0004	0.4%
2.10	SALES UNIT RATE	$/GJ	11.592	11.544	0.0482	0.4%	11.400	11.392	0.0083	0.1%
2.11	T-SERVICE UNIT RATE	$/GJ	2.572	2.522	0.0500	2.0%	2.380	2.370	0.0102	0.4%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 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.	$	1,405.32	1,200.00	205.32	17.1%	1,405.32	1,200.00	205.32	17.1%
3.3	DISTRIBUTION CHG.	$	9,781.66	8,584.07	1,197.59	14.0%	14,222.48	12,870.12	1,352.36	10.5%
3.4	LOAD BALANCING	$	11,958.70	12,712.05	(753.35)	-5.9%	21,103.93	22,434.69	(1,330.76)	-5.9%
3.5	SALES COMMDTY	$	115,447.05	115,529.46	(82.41)	-0.1%	203,730.40	203,875.87	(145.47)	-0.1%
3.6	TOTAL SALES	$	138,592.73	138,025.58	567.15	0.4%	240,462.13	240,380.68	81.45	0.0%
3.7	TOTAL T-SERVICE	$	23,145.68	22,496.12	649.56	2.9%	36,731.73	36,504.81	226.92	0.6%
3.8	SALES UNIT RATE	$/m³	0.4086	0.4069	0.0017	0.4%	0.4017	0.4016	0.0001	0.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.0682	0.0663	0.0019	2.9%	0.0614	0.0610	0.0004	0.6%
3.10	SALES UNIT RATE	$/GJ	10.841	10.797	0.0444	0.4%	10.659	10.655	0.0036	0.0%
3.11	T-SERVICE UNIT RATE	$/GJ	1.811	1.760	0.0508	2.9%	1.628	1.618	0.0101	0.6%

			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.	$	1,405.32	1,200.00	205.32	17.1%	1,405.32	1,200.00	205.32	17.1%
4.3	DISTRIBUTION CHG.	$	10,054.46	8,856.86	1,197.60	13.5%	14,463.93	13,111.59	1,352.34	10.3%
4.4	LOAD BALANCING	$	11,958.71	12,712.04	(753.33)	-5.9%	21,103.89	22,434.65	(1,330.76)	-5.9%
4.5	SALES COMMDTY	$	115,447.05	115,529.47	(82.42)	-0.1%	203,730.05	203,875.50	(145.45)	-0.1%
4.6	TOTAL SALES	$	138,865.54	138,298.37	567.17	0.4%	240,703.19	240,621.74	81.45	0.0%
4.7	TOTAL T-SERVICE	$	23,418.49	22,768.90	649.59	2.9%	36,973.14	36,746.24	226.90	0.6%
4.8	SALES UNIT RATE	$/m³	0.4094	0.4077	0.0017	0.4%	0.4021	0.4020	0.0001	0.0%
4.9	T-SERVICE UNIT RATE	$/m³	0.0690	0.0671	0.0019	2.9%	0.0618	0.0614	0.0004	0.6%
4.10	SALES UNIT RATE	$/GJ	10.862	10.818	0.0444	0.4%	10.669	10.666	0.0036	0.0%
4.11	T-SERVICE UNIT RATE	$/GJ	1.832	1.781	0.0508	2.9%	1.639	1.629	0.0101	0.6%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				**Rate 110 - Average Ind. Firm - 50% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	6,654.00	6,000.00	654.00	10.9%	6,654.00	6,000.00	654.00	10.9%
5.3	DISTRIBUTION CHG.	$	11,781.13	10,635.90	1,145.23	10.8%	192,663.39	173,837.81	18,825.58	10.8%
5.4	LOAD BALANCING	$	22,967.18	24,480.64	(1,513.46)	-6.2%	382,785.91	408,010.00	(25,224.09)	-6.2%
5.5	SALES COMMDTY	$	203,152.78	203,126.44	26.34	0.0%	3,385,875.51	3,385,436.57	438.94	0.0%
5.6	TOTAL SALES	$	244,555.09	244,242.98	312.11	0.1%	3,967,978.81	3,973,284.38	(5,305.57)	-0.1%
5.7	TOTAL T-SERVICE	$	41,402.31	41,116.54	285.77	0.7%	582,103.30	587,847.81	(5,744.51)	-1.0%
5.8	SALES UNIT RATE	$/m³	0.4086	0.4080	0.0005	0.1%	0.3977	0.3983	(0.0005)	-0.1%
5.9	T-SERVICE UNIT RATE	$/m³	0.0692	0.0687	0.0005	0.7%	0.0583	0.0589	(0.0006)	-1.0%
5.10	SALES UNIT RATE	$/GJ	10.840	10.826	0.0138	0.1%	10.553	10.567	(0.0141)	-0.1%
5.11	T-SERVICE UNIT RATE	$/GJ	1.835	1.823	0.0127	0.7%	1.548	1.563	(0.0153)	-1.0%

			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	6,654.00	6,000.00	654.00	10.9%	7,329.36	6,000.00	1,329.36	22.2%
6.3	DISTRIBUTION CHG.	$	147,234.78	132,976.24	14,258.54	10.7%	833,250.76	680,131.14	153,119.62	22.5%
6.4	LOAD BALANCING	$	382,785.88	408,009.99	(25,224.11)	-6.2%	2,121,650.86	2,243,819.74	(122,168.88)	-5.4%
6.5	SALES COMMDTY	$	3,385,875.17	3,385,436.23	438.94	0.0%	23,701,129.63	23,698,056.97	3,072.66	0.0%
6.6	TOTAL SALES	$	3,922,549.83	3,932,422.46	(9,872.63)	-0.3%	26,663,360.61	26,628,007.85	35,352.76	0.1%
6.7	TOTAL T-SERVICE	$	536,674.66	546,986.23	(10,311.57)	-1.9%	2,962,230.98	2,929,950.88	32,280.10	1.1%
6.8	SALES UNIT RATE	$/m³	0.3932	0.3942	(0.0010)	-0.3%	0.3818	0.3813	0.0005	0.1%
6.9	T-SERVICE UNIT RATE	$/m³	0.0538	0.0548	(0.0010)	-1.9%	0.0424	0.0420	0.0005	1.1%
6.10	SALES UNIT RATE	$/GJ	10.432	10.459	(0.0263)	-0.3%	10.130	10.117	0.0134	0.1%
6.11	T-SERVICE UNIT RATE	$/GJ	1.427	1.455	(0.0274)	-1.9%	1.125	1.113	0.0123	1.1%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2006-0034 @ 37.69 MJ/m³ vs (B) EB-2006-0099 @ 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.	$	1,326.36	1,200.00	126.36	10.5%	3,227.40	2,400.00	827.40	34.5%
7.3	DISTRIBUTION CHG.	$	7,702.7	6,860.83	841.86	12.3%	75,680.3	58,174.28	17,505.98	30.1%
7.4	LOAD BALANCING	$	10,371.32	11,019.54	(648.23)	-5.9%	221,011.85	235,142.50	(14,130.65)	-6.0%
7.5	SALES COMMDTY	$	203,526.55	204,204.13	(677.58)	-0.3%	3,385,875.51	3,385,436.57	438.94	0.0%
7.6	TOTAL SALES	$	222,926.92	223,284.50	(357.59)	-0.2%	3,685,795.02	3,681,153.35	4,641.67	0.1%
7.7	TOTAL T-SERVICE	$	19,400.37	19,080.37	319.99	1.7%	299,919.51	295,716.78	4,202.73	1.4%
7.8	SALES UNIT RATE	$/m³	0.3724	0.3730	(0.0006)	-0.2%	0.3695	0.3690	0.0005	0.1%
7.9	T-SERVICE UNIT RATE	$/m³	0.0324	0.0319	0.0005	1.7%	0.0301	0.0296	0.0004	1.4%
7.10	SALES UNIT RATE	$/GJ	9.882	9.897	(0.0159)	-0.2%	9.803	9.790	0.0123	0.1%
7.11	T-SERVICE UNIT RATE	$/GJ	0.860	0.846	0.0142	1.7%	0.798	0.786	0.0112	1.4%

			Rate 170 - Average Ind. Interr. - 75% LF				Rate 170 - Large Ind. Interr. - 75% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,227.40	2,400.00	827.40	34.5%	3,227.40	2,400.00	827.40	34.5%
8.3	DISTRIBUTION CHG.	$	68,621.1	53,272.96	15,348.09	28.8%	364,777.9	257,316.22	107,461.68	41.8%
8.4	LOAD BALANCING	$	221,011.84	235,142.45	(14,130.61)	-6.0%	1,547,083.01	1,645,997.54	(98,914.53)	-6.0%
8.5	SALES COMMDTY	$	3,385,875.17	3,385,436.23	438.94	0.0%	23,701,129.63	23,698,056.97	3,072.66	0.0%
8.6	TOTAL SALES	$	3,678,735.46	3,676,251.64	2,483.82	0.1%	25,616,217.94	25,603,770.73	12,447.21	0.0%
8.7	TOTAL T-SERVICE	$	292,860.29	290,815.41	2,044.88	0.7%	1,915,088.31	1,905,713.76	9,374.55	0.5%
8.8	SALES UNIT RATE	$/m³	0.3688	0.3685	0.0002	0.1%	0.3668	0.3666	0.0002	0.0%
8.9	T-SERVICE UNIT RATE	$/m³	0.0294	0.0292	0.0002	0.7%	0.0274	0.0273	0.0001	0.5%
8.10	SALES UNIT RATE	$/GJ	9.784	9.777	0.0066	0.1%	9.733	9.728	0.0047	0.0%
8.11	T-SERVICE UNIT RATE	$/GJ	0.779	0.773	0.0054	0.7%	0.728	0.724	0.0036	0.5%

Revenue Adjustment Rider (Rider E) Summary
Period: April 1st to December 31st, 2007

	Col. 1	Col. 2	Col. 3
Item No.	**Description**	**Sales Service** (cent/m^3)	**Transportation Service** (cent/m^3)
1.	**Rate 1**	0.2688	0.2310
2.	**Rate 6**	0.0798	0.0185
3.	**Rate 9**	0.2598	0.2586
4.	**Rate 100**	(0.1788)	(0.1732)
5.	**Rate 110**	(0.0327)	(0.0346)
6.	**Rate 115**	0.0132	0.0117
7.	**Rate 125**	-	-
7.	**Rate 135**	0.0038	0.0038
8.	**Rate 145**	(0.1556)	(0.1402)
9.	**Rate 170**	0.0174	0.0153
10.	**Rate 200**	0.1244	0.1204
11.	**Rate 300**	n/a	(0.0640)

Notes: Sales Service Rider includes Distribution, Gas Supply Load Balancing and Gas Supply Commodity unit rates shown on Page 2.
Transportation Service Rider equals Sales Service Rider less Gas Supply Commodity unit rate.

Derivation of Revenue Adjustment Rider (Rider E) Unit Rates
Period: April 1st to December 31st, 2007

Schedule 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
Item No.	**Description**	**Distribution Def/ (Suff) ($000) Jan-Mar 2007**	**Delivery Volumes (1000 m^3) Apr-Dec 2007**	**Unit Rate (¢/m^3)**	**Gas Supply Load Balancing Def/ (Suff) ($000) Jan-Mar 2007**	**Delivery Volumes (1000 m^3) Apr-Dec 2007**	**Unit Rate (¢/m^3)**	**Gas Supply Commodity Def/ (Suff) ($000) Jan-Mar 2007**	**Sales Volumes (1000 m^3) Apr-Dec 2007**	**Unit Rate (¢/m^3)**
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
1.	**Rate 1**	13,545	2,276,857	0.5949	(8,286)	2,276,857	(0.3639)	530	1,401,686	0.0378
2.	**Rate 6**	6,719	1,588,789	0.4229	(6,425)	1,588,789	(0.4044)	437	712,993	0.0613
3.	**Rate 9**	17	5,720	0.2974	(2)	5,720	(0.0388)	0	4,205	0.0013
4.	**Rate 100**	1,386	771,680	0.1796	(2,723)	771,680	(0.3528)	(7)	120,960	(0.0056)
5.	**Rate 110**	330	430,902	0.0766	(479)	430,902	(0.1112)	1	34,894	0.0019
6.	**Rate 115**	490	670,886	0.0730	(412)	670,886	(0.0614)	0	30,931	0.0015
7.	**Rate 125**	-	-	0.0000	-	-	0.0000	n/a	n/a	0.0000
8.	**Rate 135**	2	54,721	0.0038	(0)	54,721	0.0000	(0)	5,208	(0.0000)
9.	**Rate 145**	12	150,723	0.0080	(223)	150,723	(0.1482)	(4)	25,176	(0.0154)
10.	**Rate 170**	404	497,952	0.0812	(328)	497,952	(0.0659)	1	38,786	0.0021
11.	**Rate 200**	285	83,245	0.3428	(185)	83,245	(0.2224)	3	61,849	0.0041
12.	**Rate 300**	(15)	23,455	(0.0640)	n/a	n/a		n/a	n/a	
13.	**CDS**	-	-			-				
14.	**Total**	23,176	6,554,930		(19,063)	6,531,475		961	2,436,688	

EB-2006-0034 SALES AND TOTAL VOLUME SUMMARY

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 9	Col. 10	Col. 11	Col. 12	Col. 12
		JAN	FEB	MAR	APR	Schedule 1	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	TOTAL SALES VOLUME (10^3 m^3) - by Rate													
1.01	Rate 1	498,396	459,047	397,875	283,590	156,555	84,666	74,786	67,198	59,540	92,638	226,845	355,868	2,757,004
1.02	Rate 6	255,899	259,702	214,874	160,187	85,399	41,275	33,477	27,416	29,984	38,683	114,939	181,633	1,443,468
1.03	Rate 9	390	401	412	423	434	445	456	467	478	489	500	511	5,409
1.04	TOTAL GS SALES	754,686	719,150	613,162	444,200	242,388	126,386	108,719	95,081	90,002	131,810	342,284	538,012	4,205,881
1.05	Rate 100	35,277	32,346	29,765	21,958	14,334	7,528	6,125	6,117	7,797	10,993	18,995	27,113	218,347
1.06	Rate 110	5,100	4,984	5,059	4,338	4,058	3,540	3,283	3,355	3,679	3,886	4,155	4,602	50,038
1.07	Rate 115	3,500	3,561	3,670	3,611	3,614	3,589	2,438	3,514	3,487	3,615	3,646	3,416	41,661
1.08	Rate 135	0	0	0	37	493	626	745	894	795	762	722	134	5,208
1.09	Rate 145	6,345	4,601	5,020	3,303	2,480	1,763	1,630	1,731	1,832	2,710	4,106	5,621	41,142
1.10	Rate 170	6,292	6,086	6,260	5,329	4,245	3,497	3,683	3,694	3,302	3,634	4,970	6,431	57,424
1.11	Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
1.12	Rate 200	20,950	19,792	16,358	11,774	6,563	3,995	3,292	3,071	3,151	5,649	9,814	14,541	118,949
1.13	TOTAL LV Sales Vol	77,464	71,370	66,132	50,350	35,786	24,538	21,197	22,376	24,043	31,249	46,409	61,858	532,770
1.14	TOTAL Sales	832,150	790,519	679,294	494,551	278,174	150,924	129,916	117,457	114,045	163,058	388,693	599,870	4,738,651
1	CUMULATIVE	832,150	1,622,669	2,301,963	2,796,513	3,074,687	3,225,611	3,355,527	3,472,984	3,587,029	3,750,088	4,138,781	4,738,651	
	TOTAL VOLUME SUMMARIES (10^3 m^3) - by Rate													
2.01	Total Rate 1	808,553	744,589	646,301	459,445	254,693	137,048	121,471	110,290	96,859	150,690	364,418	581,943	4,476,300
2.02	Total Rate 6	559,560	533,402	460,346	342,637	186,426	83,058	75,841	66,127	62,244	100,088	262,314	410,055	3,142,097
2.03	Total Rate 9	538	552	566	580	594	608	622	636	649	663	677	691	7,375
2.04	TOTAL GS VOL.	1,368,651	1,278,543	1,107,212	802,661	441,713	220,714	197,933	177,052	159,752	251,442	627,409	992,689	7,625,772
2.05	Total Rate 100	222,495	200,033	192,814	139,754	94,554	48,662	40,011	39,053	44,759	71,622	120,871	172,396	1,387,023
2.06	Total Rate 110	61,303	63,200	65,025	52,877	48,960	44,719	37,213	40,309	44,073	49,273	53,969	59,508	620,429
2.07	Total Rate 115	80,830	74,307	80,172	76,269	76,023	67,758	69,310	73,419	73,612	78,147	77,275	79,072	906,196
2.08	Total Rate 125 CD	-	-	-	-	-	-	-	-	-	-	-	-	-
2.09	Total Rate 135	258	148	269	1,040	4,785	6,284	6,985	8,164	8,005	8,043	7,737	3,677	55,396
2.10	Total Rate 145	36,529	31,911	32,053	24,156	16,868	11,187	9,715	10,180	10,582	15,789	22,491	29,757	251,217
2.11	Total Rate 170	79,892	76,539	75,242	62,642	53,966	46,493	45,928	45,903	46,918	56,617	65,427	74,059	729,625
2.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	Total Rate 200	24,591	23,249	19,574	14,887	9,280	6,539	5,223	4,896	5,082	7,940	12,208	17,191	150,658
2.14	Total Rate 300	1,900	2,891	2,992	2,891	2,696	2,789	2,400	2,400	2,794	2,987	2,000	2,498	31,237
2.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	TOTAL LV VOL.	507,799	472,278	468,139	374,515	307,132	234,430	216,785	224,323	235,825	290,418	361,979	438,157	4,131,781
2.17	TOTAL VOLUME	1,876,450	1,750,821	1,575,352	1,177,177	748,845	455,144	414,718	401,376	395,577	541,860	989,387	1,430,847	11,757,552
2	CUMULATIVE	1,876,450	3,627,271	5,202,623	6,379,799	7,128,644	7,583,788	7,998,506	8,399,881	8,795,458	9,337,318	10,326,706	11,757,552	

Total Revenue Variance From EB-2006-0034 to EB-2006-0099

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 9	Col. 10	Col. 11	Col. 12	Col. 12
		JAN	**FEB**	**MAR**	**APR**	**MAY** Schedule 1	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
	EB-2006-0034 Rates (Interim Rates)													
	TOTAL REVENUE SUMMARIES ($' 000) - by Rate													
1.01	**Total Rate 1**	299,402	277,533	243,628	179,762	108,935	68,177	62,644	58,523	54,063	72,944	147,909	220,990	1,794,509
1.02	**Total Rate 6**	149,253	148,152	125,724	95,180	53,561	27,132	23,438	20,313	20,783	28,025	71,501	109,037	872,099
1.03	**Total Rate 9**	211	217	223	228	234	239	245	251	256	262	267	273	2,907
1.04	**TOTAL GS REV.**	448,866	425,903	369,575	275,170	162,729	95,548	86,327	79,087	75,102	101,231	219,677	330,300	2,669,514.8
1.05	**Total Rate 100**	30,122	27,499	26,100	19,594	13,660	7,820	6,659	6,563	7,573	10,759	17,196	23,719	197,263.7
1.06	**Total Rate 110**	5,193	5,235	5,338	4,573	4,308	3,948	3,542	3,697	3,968	4,261	4,553	4,945	53,561
1.07	**Total Rate 115**	4,548	4,358	4,584	4,439	4,433	4,159	3,818	4,315	4,312	4,502	4,484	4,464	52,415
1.08	**Total Rate 125**	-	-	-	-	259	259	259	259	259	-	-	-	1,296
1.09	**Total Rate 135**	(92)	(100)	(90)	(59)	351	451	517	611	571	561	536	339	3,596
1.10	**Total Rate 145**	4,016	3,192	3,341	2,362	1,950	1,410	1,286	1,343	1,400	1,972	2,788	3,668	28,727
1.11	**Total Rate 170**	3,194	2,999	3,009	2,217	3,718	3,180	3,223	3,228	3,132	3,616	4,404	5,225	41,145
1.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.13	**Total Rate 200**	8,409	8,068	6,709	4,907	2,843	1,827	1,519	1,427	1,464	2,462	4,101	5,967	49,704
1.14	**Total Rate 300**	7	10	11	10	9	10	8	8	10	10	7	9	110
1.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.16	**TOTAL LV REV.**	55,396	51,260	49,002	38,042	31,532	23,065	20,832	21,452	22,689	28,143	38,069	48,336	427,817
1.17	**TOTAL REVENUE**	504,263	477,163	418,577	313,212	194,261	118,613	107,158	100,538	97,791	129,374	257,746	378,635	3,097,332
1	**CUMULATIVE**	504,263	981,426	1,400,003	1,713,215	1,907,476	2,026,088	2,133,247	2,233,785	2,331,577	2,460,950	2,718,696	3,097,332	
		JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
	EB-2006-0099 Rates (July QRAM Rates)													
	TOTAL REVENUE SUMMARIES ($'000) - by Rate													
2.01	**Total Rate 1**	297,395	275,591	241,787	178,119	107,520	66,916	61,405	57,298	52,855	71,657	146,357	219,221	1,776,121
2.02	**Total Rate 6**	149,041	147,908	125,450	94,874	53,236	26,840	23,167	20,046	20,514	27,739	71,186	108,775	868,777
2.03	**Total Rate 9**	207	212	218	223	229	234	239	245	251	256	262	267	2,842
2.04	**TOTAL GS REV.**	446,643	423,711	367,455	273,216	160,985	93,991	84,811	77,589	73,619	99,653	217,805	328,263	2,647,739.8
2.05	**Total Rate 100**	30,694	27,911	26,460	19,575	13,319	7,152	5,930	5,827	6,877	10,254	17,043	23,933	194,975.9
2.06	**Total Rate 110**	5,239	5,284	5,392	4,601	4,328	3,960	3,538	3,700	3,978	4,282	4,584	4,987	53,872
2.07	**Total Rate 115**	4,525	4,326	4,560	4,410	4,403	4,117	3,779	4,281	4,279	4,475	4,456	4,438	52,050
2.08	**Total Rate 125**	-	-	-	-	244	244	244	244	244	-	-	-	1,220
2.09	**Total Rate 135**	(93)	(101)	(91)	(60)	350	450	515	609	569	559	534	338	3,579
2.10	**Total Rate 145**	4,110	3,252	3,402	2,366	1,902	1,321	1,187	1,247	1,307	1,916	2,780	3,713	28,502
2.11	**Total Rate 170**	3,169	2,973	2,983	2,186	3,685	3,145	3,187	3,192	3,096	3,583	4,374	5,198	40,770
2.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	**Total Rate 200**	8,374	8,034	6,675	4,872	2,808	1,792	1,484	1,392	1,429	2,428	4,066	5,933	49,288
2.14	**Total Rate 300**	7	10	26	25	19	10	8	8	10	10	7	9	150
2.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	**TOTAL LV REV.**	56,025	51,689	49,407	37,976	31,059	22,191	19,871	20,500	21,789	27,507	37,844	48,548	424,407
2.17	**TOTAL REVENUE**	502,667	475,401	416,861	311,192	192,044	116,182	104,683	98,089	95,408	127,160	255,649	376,811	3,072,146
2	**CUMULATIVE**	502,667	978,068	1,394,929	1,706,122	1,898,165	2,014,347	2,119,030	2,217,119	2,312,527	2,439,687	2,695,336	3,072,146	
		JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
	VARIANCE- TOTAL REVENUE ($'000) - by Rate													
3.01	**Total Rate 1**	2,006	1,942	1,841	1,644	1,415	1,260	1,239	1,225	1,208	1,287	1,552	1,769	18,388
3.02	**Total Rate 6**	213	244	274	306	324	291	271	267	270	285	315	262	3,322
3.03	**Total Rate 9**	5	5	5	5	5	5	5	6	6	6	6	6	65
3.04	**TOTAL GS REV.**	2,224	2,191	2,120	1,954	1,744	1,557	1,515	1,498	1,483	1,578	1,872	2,037	21,775.0
3.05	**Total Rate 100**	(572)	(412)	(360)	18	341	668	730	736	696	504	153	(214)	2,287.9
3.06	**Total Rate 110**	(46)	(49)	(53)	(28)	(20)	(12)	4	(3)	(10)	(21)	(31)	(42)	(311)
3.07	**Total Rate 115**	23	32	24	29	30	41	39	33	33	27	28	26	365
3.08	**Total Rate 125**	-	-	-	-	15	15	15	15	15	-	-	-	76
3.09	**Total Rate 135**	1	1	1	1	1	2	2	2	2	2	2	1	17
3.10	**Total Rate 145**	(94)	(60)	(61)	(4)	48	89	100	96	93	56	7	(45)	225
3.11	**Total Rate 170**	25	26	26	30	33	36	36	36	36	33	30	27	375
3.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	**Total Rate 200**	34	34	34	35	35	35	35	35	35	35	35	34	416
3.14	**Total Rate 300**	-	-	(15)	(15)	(10)	-	-	-	-	-	-	-	(40)
3.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	**TOTAL LV REV.**	(629)	(429)	(404)	66	473	874	960	952	900	636	225	(213)	3,410
3.17	**TOTAL REVENUE**	1,595	1,762	1,716	2,020	2,217	2,431	2,476	2,450	2,383	2,214	2,097	1,825	25,185
3	**CUMULATIVE**	1,595	3,358	5,073	7,093	9,310	11,741	14,217	16,667	19,050	21,263	23,360	25,185	

Total Distribution Revenue Variance From EB-2006-0034 to EB-2006-0099

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 9	Col. 10	Col. 11	Col. 12	Col. 12
		JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
	EB-2006-0034 Rates (Interim Rates)					Schedule 1								
	TOTAL DISTRIBUTION REVENUE SUMMARIES ($'000) - by Rate													
1.01	**Total Rate 1**	92,355	86,839	78,303	61,980	43,865	33,019	31,569	30,549	29,316	34,441	53,836	72,942	649,015
1.02	**Total Rate 6**	35,541	34,352	30,683	24,353	15,627	9,125	8,439	7,843	7,614	10,115	19,916	27,726	231,335
1.03	**Total Rate 9**	59	61	62	63	65	66	67	69	70	72	73	74	802
1.04	**TOTAL GS REV.**	127,955	121,252	109,048	86,397	59,557	42,210	40,076	38,461	37,000	44,628	73,825	100,742	881,151.3
1.05	**Total Rate 100**	8,499	7,844	7,635	6,080	4,694	3,155	2,845	2,794	2,985	3,922	5,506	7,040	62,998.3
1.06	**Total Rate 110**	1,110	1,118	1,126	1,072	1,052	1,031	1,000	1,012	1,028	1,051	1,072	1,100	12,772
1.07	**Total Rate 115**	904	892	903	896	897	882	884	892	892	901	899	902	10,744
1.08	**Total Rate 125**	-	-	-	-	259	259	259	259	259	-	-	-	1,296
1.09	**Total Rate 135**	18	13	19	18	61	76	84	96	94	95	92	199	865
1.10	**Total Rate 145**	604	561	561	489	419	354	336	339	345	406	474	542	5,430
1.11	**Total Rate 170**	524	514	510	464	431	403	402	404	406	446	479	509	5,492
1.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.13	**Total Rate 200**	364	351	316	270	216	190	177	174	176	204	245	293	2,976
1.14	**Total Rate 300**	7	10	11	10	9	10	8	8	10	10	7	9	110
1.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.16	**TOTAL LV REV.**	12,029	11,303	11,082	9,299	8,039	6,360	5,995	5,978	6,197	7,034	8,774	10,593	102,683
1.17	**TOTAL REVENUE**	139,984	132,555	120,130	95,696	67,595	48,570	46,071	44,439	43,197	51,662	82,599	111,335	983,834
1	**CUMULATIVE**	139,984	272,540	392,669	488,365	555,961	604,531	650,602	695,041	738,238	789,900	872,499	983,834	

Item No.	Col. 1	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	EB-2006-0099 Rates (July QRAM Rates)													
	TOTAL DISTRIBUTION REVENUE SUMMARIES ($'000) - by Rate													
2.01	**Total Rate 1**	87,498	82,271	74,183	58,717	41,552	31,275	29,901	28,935	27,767	32,623	51,000	69,119	614,841
2.02	**Total Rate 6**	33,167	32,057	28,633	22,726	14,583	8,515	7,875	7,319	7,105	9,439	18,585	25,877	215,880
2.03	**Total Rate 9**	54	55	56	57	59	60	61	62	64	65	66	67	727
2.04	**TOTAL GS REV.**	120,718	114,384	102,872	81,501	56,194	39,850	37,838	36,316	34,935	42,127	69,651	95,064	831,448.1
2.05	**Total Rate 100**	8,084	7,369	7,140	5,442	3,934	2,271	1,938	1,884	2,091	3,100	4,817	6,490	54,558.4
2.06	**Total Rate 110**	1,001	1,008	1,015	966	949	930	902	912	927	948	966	992	11,516
2.07	**Total Rate 115**	740	730	739	734	734	722	724	730	730	737	736	738	8,795
2.08	**Total Rate 125**	-	-	-	-	244	244	244	244	244	-	-	-	1,220
2.09	**Total Rate 135**	17	12	19	16	54	67	74	84	83	83	80	193	782
2.10	**Total Rate 145**	615	549	550	438	333	240	214	220	228	315	416	520	4,637
2.11	**Total Rate 170**	386	380	377	345	322	302	301	303	304	333	357	377	4,086
2.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	**Total Rate 200**	263	254	228	196	157	137	128	126	127	147	177	212	2,152
2.14	**Total Rate 300**	7	10	26	25	19	10	8	8	10	10	7	9	150
2.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	**TOTAL LV REV.**	11,112	10,312	10,095	8,162	6,745	4,923	4,533	4,512	4,744	5,673	7,556	9,530	87,897
2.17	**TOTAL REVENUE**	131,830	124,696	112,967	89,663	62,938	44,773	42,370	40,828	39,679	47,800	77,207	104,593	919,345
2	**CUMULATIVE**	131,830	256,526	369,493	459,156	522,094	566,867	609,237	650,065	689,745	737,544	814,751	919,345	

Item No.	Col. 1	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	VARIANCE- TOTAL DISTRIBUTION REVENUE ($'000) - by Rate													
3.01	**Total Rate 1**	4,857	4,568	4,120	3,263	2,313	1,744	1,668	1,614	1,549	1,818	2,836	3,822	34,174
3.02	**Total Rate 6**	2,374	2,295	2,050	1,627	1,044	610	564	525	509	676	1,331	1,849	15,455
3.03	**Total Rate 9**	6	6	6	6	6	6	6	6	7	7	7	7	75
3.04	**TOTAL GS REV.**	7,237	6,868	6,176	4,896	3,363	2,360	2,238	2,145	2,065	2,501	4,174	5,679	49,704.2
3.05	**Total Rate 100**	415	476	495	638	760	884	907	910	894	822	689	550	8,440
3.06	**Total Rate 110**	109	110	111	105	103	101	98	99	101	103	106	108	1,255
3.07	**Total Rate 115**	164	162	164	163	163	160	160	162	162	163	163	164	1,948
3.08	**Total Rate 125**	-	-	-	-	15	15	15	15	15	-	-	-	76
3.09	**Total Rate 135**	1	1	1	2	7	9	10	12	12	12	11	6	82
3.10	**Total Rate 145**	(11)	12	11	50	86	114	122	119	117	92	58	23	793
3.11	**Total Rate 170**	138	134	133	119	109	101	101	101	102	113	122	132	1,406
3.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	**Total Rate 200**	101	97	87	75	60	53	49	48	49	56	68	81	824
3.14	**Total Rate 300**	-	-	(15)	(15)	(10)	-	-	-	-	-	-	-	(40)
3.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	**TOTAL LV REV.**	917	991	987	1,137	1,294	1,437	1,462	1,466	1,452	1,361	1,218	1,063	14,786
3.17	**TOTAL REVENUE**	8,154	7,860	7,163	6,033	4,657	3,797	3,701	3,611	3,517	3,863	5,392	6,742	64,490
3	**CUMULATIVE**	8,154	16,014	23,176	29,209	33,867	37,664	41,364	44,976	48,493	52,356	57,747	64,489	

Total Load Balancing Revenue Variance From EB-2006-0034 to EB-2006-0099

Schedule 1

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 9	Col. 10	Col. 11	Col. 12	Col. 12
		JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
	EB-2006-0034 Rates (Interim Rates)													
	TOTAL LOAD BALANCING REVENUE SUMMARIES ($'000) - by Rate													
1.01	**Total Rate 1**	37,050	34,119	29,615	21,053	11,671	6,280	5,566	5,054	4,438	6,905	16,698	26,666	205,114
1.02	**Total Rate 6**	26,011	24,795	21,399	15,928	8,666	3,861	3,525	3,074	2,893	4,653	12,194	19,062	146,062
1.03	**Total Rate 9**	20	20	21	21	22	22	23	23	24	24	25	25	270
1.04	**TOTAL GS REV.**	63,081	58,934	51,035	37,002	20,358	10,163	9,114	8,151	7,355	11,582	28,917	45,753	351,444.9
1.05	**Total Rate 100**	9,631	8,658	8,346	6,049	4,093	2,106	1,732	1,690	1,937	3,100	5,232	7,462	60,037.6
1.06	**Total Rate 110**	2,352	2,425	2,495	2,029	1,879	1,716	1,428	1,547	1,691	1,891	2,071	2,283	23,806
1.07	**Total Rate 115**	2,456	2,258	2,436	2,317	2,310	2,059	2,106	2,231	2,236	2,374	2,348	2,402	27,532
1.08	**Total Rate 125**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.09	**Total Rate 135**	(110)	(113)	(110)	(90)	123	162	180	210	206	207	199	95	960
1.10	**Total Rate 145**	1,253	1,065	1,071	749	687	456	396	415	431	643	916	1,212	9,293
1.11	**Total Rate 170**	534	419	375	(56)	1,846	1,590	1,571	1,570	1,605	1,937	2,238	2,533	16,164
1.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.13	**Total Rate 200**	934	1,000	842	640	399	281	225	211	219	341	525	739	6,356
1.14	**Total Rate 300**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
1.16	**TOTAL LV REV.**	17,050	15,712	15,454	11,639	11,337	8,370	7,637	7,873	8,326	10,494	13,529	16,728	144,149
1.17	**TOTAL REVENUE**	80,131	74,647	66,489	48,640	31,695	18,533	16,751	16,024	15,681	22,075	42,446	62,480	495,594
1	**CUMULATIVE**	80,131	154,777	221,267	269,907	301,602	320,135	336,886	352,911	368,592	390,667	433,114	495,594	

Item No.		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	EB-2006-0099 Rates (July QRAM Rates)													
	TOTAL LOAD BALANCING REVENUE SUMMARIES ($'000) - by Rate													
2.01	**Total Rate 1**	40,096	36,924	32,050	22,784	12,630	6,796	6,024	5,469	4,803	7,473	18,071	28,858	221,977
2.02	**Total Rate 6**	28,326	27,002	23,303	17,345	9,437	4,205	3,839	3,347	3,151	5,067	13,279	20,758	159,058
2.03	**Total Rate 9**	20	21	21	22	22	23	24	24	25	25	26	26	279
2.04	**TOTAL GS REV.**	68,442	63,946	55,375	40,150	22,090	11,024	9,886	8,841	7,979	12,564	31,376	49,642	381,314.4
2.05	**Total Rate 100**	10,615	9,544	9,199	6,668	4,511	2,322	1,909	1,863	2,135	3,417	5,767	8,225	66,174.4
2.06	**Total Rate 110**	2,507	2,585	2,659	2,163	2,002	1,829	1,522	1,649	1,803	2,015	2,207	2,434	25,375
2.07	**Total Rate 115**	2,597	2,388	2,576	2,451	2,443	2,177	2,227	2,359	2,365	2,511	2,483	2,541	29,117
2.08	**Total Rate 125**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.09	**Total Rate 135**	(110)	(113)	(110)	(89)	128	169	188	219	215	216	208	99	1,020
2.10	**Total Rate 145**	1,334	1,136	1,142	803	725	481	417	437	455	678	966	1,278	9,852
2.11	**Total Rate 170**	647	528	482	33	1,923	1,656	1,636	1,635	1,671	2,017	2,331	2,638	17,198
2.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	**Total Rate 200**	1,002	1,064	896	681	425	299	239	224	233	363	559	787	6,770
2.14	**Total Rate 300**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	**TOTAL LV REV.**	18,593	17,130	16,844	12,708	12,156	8,932	8,138	8,387	8,877	11,218	14,520	18,001	155,506
2.17	**TOTAL REVENUE**	87,035	81,077	72,219	52,859	34,246	19,956	18,024	17,227	16,855	23,782	45,896	67,643	536,820
2	**CUMULATIVE**	87,035	168,112	240,330	293,189	327,435	347,392	365,416	382,643	399,498	423,281	469,177	536,820	

Item No.		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	VARIANCE- TOTAL LOAD BALANCING REVENUE ($'000) - by Rate													
3.01	**Total Rate 1**	(3,046)	(2,805)	(2,435)	(1,731)	(959)	(516)	(458)	(415)	(365)	(568)	(1,373)	(2,192)	(16,865)
3.02	**Total Rate 6**	(2,314)	(2,206)	(1,904)	(1,417)	(771)	(344)	(314)	(274)	(257)	(414)	(1,085)	(1,696)	(12,996)
3.03	**Total Rate 9**	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(10)
3.04	**TOTAL GS REV.**	(5,361)	(5,012)	(4,340)	(3,149)	(1,731)	(861)	(772)	(690)	(623)	(983)	(2,459)	(3,889)	(29,871.5)
3.05	**Total Rate 100**	(984)	(885)	(853)	(618)	(418)	(215)	(177)	(173)	(198)	(317)	(535)	(763)	(6,136.8)
3.06	**Total Rate 110**	(155)	(160)	(164)	(134)	(124)	(113)	(94)	(102)	(111)	(125)	(136)	(150)	(1,569)
3.07	**Total Rate 115**	(141)	(130)	(140)	(133)	(133)	(119)	(121)	(128)	(129)	(137)	(135)	(138)	(1,585)
3.08	**Total Rate 125**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.09	**Total Rate 135**	(0)	(0)	(0)	(1)	(5)	(7)	(8)	(9)	(9)	(9)	(8)	(4)	(60)
3.10	**Total Rate 145**	(81)	(71)	(71)	(54)	(38)	(25)	(22)	(23)	(24)	(35)	(50)	(66)	(559)
3.11	**Total Rate 170**	(113)	(108)	(107)	(89)	(76)	(66)	(65)	(65)	(66)	(80)	(93)	(105)	(1,033)
3.12	**Total Rate 180**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	**Total Rate 200**	(68)	(64)	(54)	(41)	(25)	(18)	(14)	(13)	(14)	(22)	(34)	(47)	(414)
3.14	**Total Rate 300**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.15	**Total CDS**	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	**TOTAL LV REV.**	(1,543)	(1,418)	(1,390)	(1,070)	(820)	(562)	(501)	(513)	(551)	(724)	(991)	(1,274)	(11,357)
3.17	**TOTAL REVENUE**	(6,904)	(6,430)	(5,729)	(4,219)	(2,551)	(1,423)	(1,273)	(1,203)	(1,174)	(1,707)	(3,450)	(5,163)	(41,228)
3	**CUMULATIVE**	(6,904)	(13,334)	(19,063)	(23,282)	(25,833)	(27,256)	(28,529)	(29,732)	(30,907)	(32,613)	(36,063)	(41,226)	

Filed: 2007-02-23
Interim Rate Order
EB-2006-0034
Exhibit H2
Tab 8
Schedule 1
Page 7 of 7

Total Commodity Revenue Variance From EB-2006-0034 to EB-2006-0099

Schedule 1

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 9	Col. 10	Col. 11	Col. 12	Col. 12
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	EB-2006-0034 Rates (Interim Rates)													
	TOTAL COMMODITY REVENUE SUMMARIES ($'000) - by Rate													
1.01	Total Rate 1	169,997	156,575	135,710	96,729	53,399	28,878	25,509	22,920	20,308	31,598	77,374	121,382	940,381
1.02	Total Rate 6	87,701	89,004	73,641	54,899	29,268	14,146	11,473	9,396	10,276	13,257	39,392	62,249	494,702
1.03	Total Rate 9	132	136	140	144	147	151	155	159	162	166	170	174	1,836
1.04	TOTAL GS REV.	257,831	245,716	209,492	151,772	82,814	43,175	37,137	32,475	30,747	45,021	116,935	183,805	1,436,918.6
1.05	Total Rate 100	11,992	10,996	10,119	7,465	4,873	2,559	2,082	2,079	2,651	3,737	6,458	9,217	74,227.8
1.06	Total Rate 110	1,731	1,692	1,717	1,472	1,377	1,201	1,114	1,139	1,248	1,319	1,410	1,562	16,983
1.07	Total Rate 115	1,188	1,209	1,245	1,226	1,227	1,218	828	1,193	1,184	1,227	1,238	1,159	14,140
1.08	Total Rate 125	-	-	-	-	-	-	-	-	-	-	-	-	-
1.09	Total Rate 135	0	0	0	13	168	213	253	304	270	259	246	46	1,771
1.10	Total Rate 145	2,160	1,566	1,709	1,124	844	600	555	589	624	922	1,397	1,913	14,003
1.11	Total Rate 170	2,136	2,065	2,125	1,809	1,441	1,187	1,250	1,254	1,121	1,233	1,687	2,183	19,490
1.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
1.13	Total Rate 200	7,110	6,718	5,552	3,996	2,227	1,356	1,117	1,042	1,069	1,917	3,331	4,935	40,371
1.14	Total Rate 300	-	-	-	-	-	-	-	-	-	-	-	-	-
1.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
1.16	TOTAL LV REV.	26,317	24,245	22,466	17,104	12,156	8,334	7,200	7,600	8,167	10,615	15,766	21,015	180,985
1.17	TOTAL REVENUE	284,147	269,961	231,958	168,876	94,970	51,510	44,336	40,075	38,913	55,636	132,701	204,820	1,617,904
1	CUMULATIVE	284,147	554,108	786,066	954,942	1,049,913	1,101,422	1,145,759	1,185,833	1,224,747	1,280,383	1,413,084	1,617,904	

Item No.	Col. 1	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	EB-2006-0099 Rates (July QRAM Rates)													
	TOTAL COMMODITY REVENUE SUMMARIES ($'000) - by Rate													
2.01	Total Rate 1	169,802	156,396	135,555	96,618	53,338	28,845	25,479	22,894	20,285	31,561	77,285	121,243	939,303
2.02	Total Rate 6	87,548	88,849	73,513	54,803	29,217	14,121	11,453	9,380	10,258	13,234	39,323	62,140	493,839
2.03	Total Rate 9	132	136	140	144	147	151	155	159	162	166	170	174	1,835
2.04	TOTAL GS REV.	257,483	245,381	209,208	151,565	82,702	43,118	37,087	32,432	30,706	44,962	116,778	183,557	1,434,977.3
2.05	Total Rate 100	11,995	10,998	10,121	7,466	4,874	2,560	2,083	2,080	2,651	3,738	6,459	9,219	74,243.1
2.06	Total Rate 110	1,731	1,691	1,717	1,472	1,377	1,201	1,114	1,139	1,248	1,319	1,410	1,562	16,981
2.07	Total Rate 115	1,188	1,208	1,245	1,225	1,226	1,218	827	1,192	1,183	1,227	1,237	1,159	14,138
2.08	Total Rate 125	-	-	-	-	-	-	-	-	-	-	-	-	-
2.09	Total Rate 135	0	0	0	13	168	214	254	305	271	260	246	46	1,777
2.10	Total Rate 145	2,161	1,567	1,710	1,125	845	600	555	590	624	923	1,398	1,915	14,013
2.11	Total Rate 170	2,135	2,065	2,124	1,808	1,440	1,187	1,250	1,253	1,121	1,233	1,687	2,183	19,487
2.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
2.13	Total Rate 200	7,109	6,717	5,551	3,996	2,227	1,356	1,117	1,042	1,069	1,917	3,330	4,934	40,366
2.14	Total Rate 300	-	-	-	-	-	-	-	-	-	-	-	-	-
2.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
2.16	TOTAL LV REV.	26,319	24,247	22,468	17,105	12,158	8,335	7,201	7,601	8,168	10,616	15,768	21,017	181,005
2.17	TOTAL REVENUE	283,802	269,628	231,676	168,671	94,859	51,453	44,288	40,033	38,874	55,578	132,546	204,574	1,615,982
2	CUMULATIVE	283,802	553,430	785,106	953,776	1,048,636	1,100,089	1,144,377	1,184,410	1,223,284	1,278,862	1,411,408	1,615,982	

Item No.	Col. 1	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	VARIANCE- TOTAL COMMODITY REVENUE ($'000) - by Rate													
3.01	Total Rate 1	195	179	156	111	61	33	29	26	23	36	89	139	1,078
3.02	Total Rate 6	153	155	128	96	51	25	20	16	18	23	69	109	863
3.03	Total Rate 9	0	0	0	0	0	0	0	0	0	0	0	0	0
3.04	TOTAL GS REV.	348	335	284	207	112	58	49	43	41	59	157	248	1,941.3
3.05	Total Rate 100	(2)	(2)	(2)	(2)	(1)	(1)	(0)	(0)	(1)	(1)	(1)	(2)	(15.3)
3.06	Total Rate 110	0	0	0	0	0	0	0	0	0	0	0	0	2
3.07	Total Rate 115	0	0	0	0	0	0	0	0	0	0	0	0	2
3.08	Total Rate 125	-	-	-	-	-	-	-	-	-	-	-	-	-
3.09	Total Rate 135	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(6)
3.10	Total Rate 145	(2)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(10)
3.11	Total Rate 170	0	0	0	0	0	0	0	0	0	0	0	0	3
3.12	Total Rate 180	-	-	-	-	-	-	-	-	-	-	-	-	-
3.13	Total Rate 200	1	1	1	1	0	0	0	0	0	0	0	1	5
3.14	Total Rate 300	-	-	-	-	-	-	-	-	-	-	-	-	-
3.15	Total CDS	-	-	-	-	-	-	-	-	-	-	-	-	-
3.16	TOTAL LV REV.	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(19)
3.17	TOTAL REVENUE	345	333	282	205	111	57	48	41	40	58	155	246	1,922
3	CUMULATIVE	345	678	961	1,166	1,277	1,334	1,382	1,423	1,463	1,521	1,676	1,922	

REVENUE TO COST/
RATE OF RETURN COMPARISONS
DEC. 31, 2007
(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 300 CDS	Col. 15 RATE 305	Col. 16 RATE 325 & 330	Col. 17 DIRECT PURCHASE
1.	Sales and Trans. Revenue	3,100.67	1,794.58	872.14	2.91	197.26	53.56	52.42	1.30	3.60	28.73	41.15	49.70	0.00	0.00	0.12	1.66	1.56
2.	Unbilled Revenues	(2.10)	1.05	(3.56)	0.00	0.36	(0.01)	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	3,098.57	1,795.63	868.58	2.91	197.63	53.55	52.42	1.30	3.60	28.78	41.15	49.70	0.00	0.00	0.12	1.66	1.56
4.	Cost of Service	3,098.57	1,785.28	863.51	3.38	201.10	53.16	56.60	2.96	3.87	29.27	46.13	49.93	0.00	0.00	0.20	1.66	1.56
5.	Over/Under Contribution	(0.00)	10.35	5.06	(0.47)	(3.48)	0.38	(4.18)	(1.66)	(0.28)	(0.49)	(4.98)	(0.22)	0.00	0.00	(0.08)	(0.00)	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m^3)	0.00	2.31	1.61	(64.13)	(2.51)	0.62	(4.62)	n/a	(5.01)	(1.93)	(6.83)	(1.47)	0.00	0.00	(2.45)	N/A	N/A
7.	Rate Base	3,743.60	2,313.16	874.80	5.19	230.03	41.29	24.57	9.66	1.78	21.86	22.38	12.27	0.00	0.00	0.67	185.95	N/A
8.	Return on Rate Base	6.08%	6.39%	6.49%	-0.40%	5.00%	6.74%	-6.01%	-6.14%	-5.01%	4.50%	-9.73%	4.79%	0.00%	0.00%	-1.99%	6.02%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	1.01	0.86	0.98	1.01	0.93	0.44	0.93	0.98	0.89	1.00	0.00	0.00	0.61	1.00	1.00
10.	Revenue to Cost Ratio 2006 Board Decision	1.00	1.00	1.00	0.87	0.99	1.01	0.93	n/a	0.89	1.02	0.94	1.00	0.00	0.00	0.84	1.01	0.58

REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
DEC. 31, 2007

(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 300 CDS	Col. 15 RATE 305	Col. 16 RATE 325 & 330	Col. 17 DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,482.68	854.14	377.41	1.07	123.04	36.58	38.28	1.30	1.83	14.73	21.66	9.33	0.00	0.00	0.12	1.66	1.56
2.	Unbilled Revenues	(2.10)	1.05	(3.56)	0.00	0.36	(0.01)	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,480.58	855.20	373.85	1.07	123.40	36.57	38.28	1.30	1.83	14.78	21.66	9.33	0.00	0.00	0.12	1.66	1.56
4.	Cost of Service	1,480.58	844.84	368.78	1.54	126.87	36.18	42.46	2.96	2.10	15.27	26.64	9.55	0.00	0.00	0.20	1.66	1.56
5.	Over/Under Contribution	0.00	10.36	5.06	(0.47)	(3.48)	0.38	(4.18)	(1.66)	(0.28)	(0.49)	(4.98)	(0.22)	0.00	0.00	(0.08)	(0.00)	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m^3)		2.31	1.61	(64.18)	(2.51)	0.62	(4.62)	n/a	(5.01)	(1.93)	(6.83)	(1.47)	0.00	0.00	0.00	N/A	N/A
7.	Rate Base	3,726.42	2,303.17	869.56	5.17	229.24	41.11	24.42	9.66	1.76	21.71	22.17	11.84	0.00	0.00	0.67	185.95	N/A
8.	Return on Rate Base	6.08%	6.39%	6.49%	-0.43%	5.00%	6.74%	-6.08%	-6.14%	-5.13%	4.49%	-9.88%	4.75%	0.00%	0.00%	-1.99%	6.02%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	1.01	0.69	0.97	1.01	0.90	0.44	0.87	0.97	0.81	0.98	0.00	0.00	0.61	1.00	1.00
10.	Revenue to Cost Ratio 2006 Board Decision	1.00	1.01	1.01	0.69	0.98	1.01	0.90	n/a	0.87	1.03	0.89	0.98	0.00	0.00	0.84	1.01	0.58

Functionalization of
Ontario Utility Rate Base
Year Ended Dec. 31, 2007

(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
		Net Rate Base	Gas Supply	Storage	Sales Stations	Distribution Measurement	Services	Mains	Meters	Rental Equipment	Sales/ Marketing	Customer Accounting	Unidenti- fiable	Entrac	GST Revenue
1.	**Gas Supply**	2.37	0.00	2.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Distribution Plant														
2.1	Land (incl offers to buy)	8.32	0.08	0.00	0.04	0.02	0.99	0.80	0.02	0.00	1.34	3.55	1.49	0.00	0.00
2.2	Structures & Improvements	59.37	0.58	0.00	0.28	0.14	7.04	5.71	0.14	0.00	9.56	25.31	10.61	0.00	0.00
2.3	Mains	1,279.80	0.00	0.00	0.00	0.00	0.00	1,279.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Meas. Reg. & Telemetering	158.40	0.00	0.00	84.28	74.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.5	Services	1,069.60	0.00	0.00	0.00	0.00	1,069.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Meters	229.10	0.00	0.00	0.00	0.00	0.00	0.00	229.10	0.00	0.00	0.00	0.00	0.00	0.00
2.	Total Distribution Plant	2,804.59	0.66	0.00	84.60	74.28	1,077.63	1,286.31	229.26	0.00	10.90	28.86	12.09	0.00	0.00
	General Plant														
3.1	Land (incl offers to buy)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Structures & Improvements	3.40	0.00	0.00	0.00	0.00	1.14	0.15	0.00	0.00	0.43	1.20	0.48	0.00	0.00
3.3	Office Furniture & Equip.	7.10	0.01	0.01	0.01	0.87	1.15	1.42	0.33	0.12	0.17	0.22	2.79	0.00	0.00
3.4	Transportation Equipment	18.50	0.00	0.00	0.00	0.04	5.49	12.37	0.00	0.00	0.60	0.00	0.00	0.00	0.00
3.5	Heavy Work Equipment	9.30	0.00	0.00	0.00	0.02	2.76	6.22	0.00	0.00	0.30	0.00	0.00	0.00	0.00
3.6	Tools & Work Equip.	15.30	0.00	0.00	0.00	0.00	7.65	7.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.7	Rental Equip.	7.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.70	0.00	0.00	0.00	0.00	0.00
3.8	Communication Equip.	3.20	0.04	0.00	0.03	0.91	0.28	0.40	0.00	0.00	0.30	0.55	0.70	0.00	0.00
3.9	Compressors	1.30	0.00	0.00	0.00	0.00	0.39	0.87	0.00	0.00	0.04	0.00	0.00	0.00	0.00
3.10	Computer Equipment	70.57	1.69	0.24	1.64	5.99	11.38	18.43	5.99	0.11	0.63	16.29	8.17	0.00	0.00
3.11	S.I.M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.12	Entrac	12.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.43	0.00
3.	Total General Plant	148.80	1.75	0.25	1.68	7.84	30.23	47.51	6.32	7.93	2.47	18.27	12.13	12.43	0.00
4.	**Other Plant**	0.10	0.00	0.00	0.00	0.00	0.04	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.	**Plant Held for Future Use**	1.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Other Items														
6.1	Working Capital Allowance	600.80	627.84	23.23	(0.90)	(0.99)	6.58	13.48	0.00	0.00	1.13	(55.33)	0.28	0.00	(14.53)
6.	Total Other Items	600.80	627.84	23.23	(0.90)	(0.99)	6.58	13.48	0.00	0.00	1.13	(55.33)	0.28	0.00	(14.53)
7.	**Total Rate Base**	3,557.65	630.25	25.85	85.38	81.13	1,115.47	1,347.35	235.58	7.93	14.51	(8.20)	24.50	12.43	(14.53)

Functionalization of
Ontario Utility Working Capital
Year Ended Dec. 31, 2007
(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
		Total Requirement	Gas Supply	Storage	Sales Stations	Distribution Measurement	Services	Mains	Sales/ Marketing	Customer Accounting	Unidenti-fiable	GST Revenue
	Working Capital Allowance											
1.	Prepaid Expenses	2.70	0.00	0.00	0.00	0.00	0.33	0.33	0.02	0.00	2.01	0.00
	Materials & Supplies											
2.1	NGV Inventory	1.34	0.00	0.00	0.00	0.00	0.00	0.00	1.34	0.00	0.00	0.00
2.2	Pipe	3.09	0.00	0.00	0.00	0.00	0.70	2.39	0.00	0.00	0.00	0.00
2.3	Warehouse Inventory	5.07	0.00	0.00	0.00	0.00	2.53	2.53	0.00	0.00	0.00	0.00
2.4	Holding Account	9.14	0.00	0.00	0.00	0.00	4.57	4.57	0.00	0.00	0.00	0.00
3.	Mortgages Receivable	0.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.90	0.00
4.	Merchandise Sales Financed	0.10	0.00	0.00	0.00	0.00	0.00	0.00	2.60	0.00	(2.50)	0.00
5.	Rebilled Construction Work	6.90	0.00	0.00	0.00	0.00	0.00	6.90	0.00	0.00	0.00	0.00
6.	Gas in Inventory	613.10	613.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Customer Security Deposits	(42.80)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(42.80)	0.00	0.00
	Working Cash Allowance											
8.1	Gas Costs/O&M	(2.20)	20.67	1.37	(0.92)	(1.01)	(2.11)	(4.37)	(2.89)	(12.81)	(0.14)	0.00
8.2	GST	3.46	(5.93)	21.86	0.02	0.02	0.54	1.13	0.06	0.28	0.00	(14.53)
9.	**Total Working Capital**	600.80	627.84	23.23	(0.90)	(0.99)	6.58	13.48	1.13	(55.33)	0.28	(14.53)

Functionalization of
Ontario Utility Net Investments
Year Ended Dec. 31, 2007
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(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
		Investment and Revenues	Gas Supply	Storage	Sales Stations	Distribution Measurement	Services	Mains	Meters	Rental Equipment	Sales/ Marketing	Customer Accounting	Unidenti-fiable	Entrac
	Investment Costs													
1.1	Depreciation	220.99	0.59	0.08	8.07	8.92	85.44	90.96	9.96	1.06	0.70	6.52	3.71	4.98
1.2	Municipal Taxes	34.82	0.02	0.00	0.16	0.15	10.95	21.80	0.01	0.00	0.37	0.97	0.41	0.00
1.3	Capital Taxes	9.80	0.01	0.00	0.04	0.04	3.08	6.13	0.00	0.00	0.10	0.27	0.11	0.00
1.	Total Investments	265.61	0.62	0.08	8.27	9.12	99.47	118.89	9.97	1.06	1.17	7.76	4.23	4.98
	Miscellaneous Revenues													
2.1	Rentals	(1.30)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(1.30)	0.00	0.00	0.00	0.00
2.2	Transactional Services	(3.63)	(3.74)	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	Miscellaneous Income	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Late Payment Penalties	(8.00)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(8.00)	0.00	0.00
2.5	Sale and Rental of Property	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Customer Accounting Charge	(9.40)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(9.40)	0.00	0.00
2.7	Meter Charge	(0.20)	0.00	0.00	0.00	0.00	0.00	0.00	(0.20)	0.00	0.00	0.00	0.00	0.00
2.8	Service Alteration Charge	(0.84)	0.00	0.00	0.00	0.00	(0.84)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Total Revenues	(23.37)	(3.74)	0.11	0.00	0.00	(0.84)	0.00	(0.20)	(1.30)	0.00	(17.40)	0.00	0.00
3.	**Net Investments Total**	242.23	(3.12)	0.19	8.27	9.12	98.62	118.89	9.77	(0.24)	1.17	(9.64)	4.23	4.98

Functionalization of
Ontario Utility O&M
Year Ended Dec. 31, 2007

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Cost of Service	Fringe Benefits	Sub-Total	Supervision	Sub-Total	A&G Overhead	Total
	Gas Supply							
1.1	Gas Purchased	2,066.26	0.00	2,066.26	0.00	2,066.26	0.00	2,066.26
1.2	Gas Storage	131.10	0.33	131.43	0.00	131.43	0.00	131.43
1.3	A&G	0.00	0.00	0.00	0.00	0.00	12.78	12.78
1.4	System Gas Management	0.80	0.08	0.88	0.00	0.88	0.00	0.88
1.5	Direct Purchase Management	0.94	0.62	1.56	0.00	1.56	0.00	1.56
1.	Total Gas Supply	2,199.10	1.03	2,200.13	0.00	2,200.13	12.78	2,212.91
	Distribution Costs							
	Operating Costs							
2.1.1	Chart Processing	1.56	0.29	1.85	1.24	3.10	0.60	3.70
2.1.2	Distribution Sta.	1.02	0.17	1.19	0.80	1.99	0.39	2.37
2.1.3	Sub-total	2.58	0.46	3.04	2.04	5.08	0.99	6.07
2.1.4	Supervision M&R	0.79	0.22	1.01	(1.01)	0.00	0.00	0.00
2.1.5	System Operation	27.18	5.67	32.85	8.36	41.21	7.99	49.19
2.1.6	Sub-total	30.55	6.35	36.90	9.39	46.29	8.97	55.26
2.1.7	Supervision Dist Op	6.45	2.94	9.39	(9.39)	0.00	0.00	0.00
2.1.8	Gas Dispatched	4.16	0.66	4.82	0.00	4.82	0.93	5.75
2.1	Total Operating Costs	41.16	9.95	51.11	0.00	51.11	9.91	61.01
	Maintenance Costs							
2.2.1	Distribution Sys Reg	0.17	0.04	0.21	0.43	0.63	0.12	0.76
2.2.2	Sales Meters	0.47	0.12	0.59	1.22	1.81	0.35	2.16
2.2.3	Other Meters	2.37	0.70	3.07	6.42	9.49	1.84	11.33
2.2.4	Instruments	0.70	0.12	0.82	1.72	2.54	0.49	3.03
2.2.5	Sub-total M&R	3.71	0.98	4.69	9.79	14.47	2.81	17.28
2.2.6	Supervision M&R	3.18	1.13	4.31	(4.31)	0.00	0.00	0.00
2.2.7	Mains	6.65	1.99	8.64	5.27	13.90	2.70	16.60
2.2.8	Structures	0.13	0.00	0.13	0.08	0.21	0.04	0.25
2.2.9	Sub-total Mntce	13.67	4.09	17.76	10.83	28.59	5.54	34.13
2.2.10	Supervision Dist Mntce	8.30	2.53	10.83	(10.83)	0.00	0.00	0.00
2.2	Total Maintenance Costs	21.97	6.62	28.59	0.00	28.59	5.54	34.13
2.	Total Distribution Costs	63.13	16.57	79.70	0.00	79.70	15.45	95.15

Functionalization of
Ontario Utility O&M
Year Ended Dec. 31, 2007

(millions of dollars)

		Col. 1 Cost of Service	Col. 2 Fringe Benefits	Col. 3 Sub-Total	Col. 4 Supervision	Col. 5 Sub-Total	Col. 6 A&G Overhead	Col. 7 Total
	Customer Service Costs							
	Operating Costs							
3.1.1	Heating Equipment Service	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.1.1	Other Service Work	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.1.2	Inspect Appl Inst.	1.64	0.30	1.94	0.38	2.32	0.45	2.77
3.1.3	Sub-total Service Work	1.64	0.30	1.94	0.38	2.32	0.45	2.77
3.1.4	Mtr Locks,Unlks,Exchanges	7.78	0.80	8.58	1.66	10.24	1.98	12.22
3.1.5	Jobbing Contracts Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.1.6	Sub-total	9.42	1.10	10.52	2.03	12.56	2.43	14.99
3.1.7	Training & Supervision	2.05	0.59	2.64	(2.64)	0.00	0.00	0.00
3.1	Total Operating Costs	11.47	1.69	13.16	(0.60)	12.56	2.43	14.99
	Maintenance Costs							
3.2.1	Co Equip on Cust. Premises	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2.2	Service Lines	2.27	0.85	3.12	0.60	3.73	0.72	4.45
3.2	Total Maintenance Costs	2.27	0.85	3.12	0.60	3.73	0.72	4.45
3.	Total Customer Service Costs	13.74	2.54	16.28	0.00	16.28	3.16	19.44
	Sales/Marketing Costs							
4.1	Residential Promotion	5.24	0.33	5.57	0.43	5.99	1.16	7.15
4.2	Commercial Promotion	1.89	0.73	2.62	0.20	2.82	0.55	3.37
4.3	Industrial Promotion	3.11	0.60	3.71	0.29	4.00	0.78	4.78
4.4	Res/Comm Promotions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.4	General Sales Promotion	3.29	0.86	4.15	0.32	4.47	0.87	5.33
4.5	Merchandising Expenses	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	1.26	0.16	1.42	0.11	1.53	0.30	1.83
4.7	Contract Administration Costs	2.62	0.62	3.24	0.25	3.49	0.68	4.16
4.8	Sub-total	17.41	3.30	20.71	1.59	22.30	4.32	26.62
4.9	General Supervision	1.20	0.39	1.59	(1.59)	0.00	0.00	0.00
4.10	DSM - Program	16.99	0.00	16.99	0.00	16.99	3.29	20.28
4.11	DSM - General	5.01	1.83	6.84	0.00	6.84	1.33	8.16
4.	Total Sales	40.61	5.52	46.13	0.00	46.13	8.94	55.07

Functionalization of
Ontario Utility O&M
Year Ended Dec. 31, 2007

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Cost of Service	Fringe Benefits	Sub-Total	Supervision	Sub-Total	A&G Overhead	Total
	Customer Accounting Costs							
5.1	Billing	56.33	0.09	56.42	2.60	59.02	11.44	70.46
5.2	Service & Billing Enquiry	27.58	0.02	27.60	1.27	28.87	5.60	34.46
5.3	Meter Reading	9.55	0.02	9.57	0.44	10.01	1.94	11.95
5.4	Credit & Collection	17.73	0.02	17.75	0.82	18.56	3.60	22.16
5.5	Sub-total	111.19	0.14	111.33	5.13	116.46	22.58	139.04
5.6	Supervision	4.40	0.73	5.13	(5.13)	0.00	0.00	0.00
5.7	Uncollectible Accounts	15.10	0.00	15.10	0.00	15.10	2.93	18.03
5.	Total Customer Accounting	130.69	0.88	131.56	0.00	131.56	25.50	157.07
6.	**Fringe Benefits**	36.16	(36.16)	0.00	0.00	0.00	0.00	0.00
7.	**Admin & Gen Overhead**	56.21	9.62	65.84	0.00	65.84	(65.84)	0.00
8.	Sub-total A&G and F/B	92.37	(26.54)	65.84	0.00	65.84	(65.84)	0.00
9.	**Total Operating & Maintenance**	2,539.63	0.00	2,539.63	(0.00)	2,539.63	0.00	2,539.63
10.	Deferred Tax	9.20	0.00	9.20	0.00	9.20	0.00	9.20
11.	Fixed Financing Costs	1.30	0.00	1.30	0.00	1.30	0.00	1.30
12.	**TOTAL O&M EXPENSE**	2,550.13	0.00	2,550.13	(0.00)	2,550.13	0.00	2,550.13

CLASSIFICATION OF RATE BASE
DEC. 31, 2007

(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
				GAS SUPPLY											
				PRODUCT COSTS		LOAD BALANCING			STORAGE COSTS			DISTRIBUTION COSTS			
Item No.	Description	Total	Specific Classes	Winter Commodity	Annual Commodity	Peak	Seasonal	Annual	Deliverability	Space	Winter	TP Capacity	HP Capacity	LP Capacity	Commodity
	GAS SUPPLY														
1.	Gas Supply	630.25	0.00	0.00	17.06	0.00	613.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09
2.	Storage	25.85	0.00	0.00	0.00	0.00	0.00	0.00	12.66	13.19	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION														
3.	Mains	1,347.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	289.60	103.29	524.95	0.00
4.	Distribution Reg.	81.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.60	9.13	46.40	0.00
	CUSTOMER														
5.	Sales Station	85.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	235.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	1,115.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	7.93	5.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	14.51	1.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.99	0.71	3.60	0.00
10.	Customer Accounting	(8.20)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11.	GST Revenue	(14.53)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	**Sub-total**	3,520.71	7.52	0.00	17.06	0.00	613.10	0.00	12.66	13.19	0.00	317.18	113.13	574.95	0.09
13.	Unidentifiable	24.50	0.05	0.00	0.12	0.00	4.25	0.00	0.09	0.09	0.00	2.20	0.78	3.99	0.00
14	Entrac	12.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	**Total Classified**	3,557.65	7.57	0.00	17.18	0.00	617.35	0.00	12.75	13.28	0.00	319.38	113.91	578.94	0.09

CLASSIFICATION OF RATE BASE
DEC. 31, 2007

(millions of dollars)

		Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24	Col. 25	Col. 26
		CUSTOMER RELATED INVESTMENTS					NUMBER OF CUSTOMERS						
Item No.	Description	Meters	Sales Stations	Services	Customer Plant	Rentals	Commercial/ Industrial	Contracts	Direct Purchase	Total	Readings Processed	Entrac	GST Revenue
	GAS SUPPLY												
1.	Gas Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION												
3.	Mains	0.00	0.00	0.00	429.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Distribution Reg.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER												
5.	Sales Station	0.00	85.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	235.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	0.00	0.00	1,115.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	0.00	0.00	0.00	0.00	2.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.30	0.00	0.00	0.00
10.	Customer Accounting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(8.20)	0.00	0.00	0.00
11.	GST Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(14.53)
12.	**Sub-total**	235.58	85.38	1,115.47	429.51	2.31	0.00	0.00	0.00	(1.90)	0.00	0.00	(14.53)
13.	Unidentifiable	1.63	0.59	7.73	2.98	0.02	0.00	0.00	0.00	(0.01)	0.00	0.00	0.00
14	Entrac	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.43	0.00
15	**Total Classified**	237.21	85.97	1,123.20	432.48	2.33	0.00	0.00	0.00	(1.91)	0.00	12.43	(14.53)

CLASSIFICATION OF NET INVESTMENT
DEC. 31, 2007

(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
				GAS SUPPLY													
				PRODUCT COSTS		LOAD BALANCING					STORAGE COSTS			DISTRIBUTION COSTS			
Item No.	Description	Total	Specific Classes	Winter Commodity	Annual Commodity	Peak	Seasonal	Annual	DSM Peak	DSM Annual	Deliverability	Space	Winter	TP Capacity	HP Capacity	LP Capacity	Commodity
	GAS SUPPLY																
1.	Gas Supply	(3.12)	0.00	0.00	0.02	0.00	0.62	(3.74)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)
2.	Storage	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.10	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION																
3.	Mains	118.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.55	9.11	46.32	0.00
4.	Distribution Reg.	9.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.88	1.03	5.21	0.00
	CUSTOMER																
5.	Sales Station	8.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	9.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	98.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	(0.24)	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	1.17	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.06	0.29	0.00
10.	Customer Accounting	(9.64)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11.	**Sub-total**	233.02	0.48	0.00	0.02	0.00	0.62	(3.74)	0.00	0.00	0.09	0.10	0.00	28.59	10.20	51.82	(0.02)
12.	Unidentifiable	4.23	0.01	0.00	0.02	0.00	0.73	0.00	0.00	0.00	0.02	0.02	0.00	0.38	0.14	0.69	0.00
13	Entrac	4.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14.	**Total Classified**	242.23	0.49	0.00	0.04	0.00	1.35	(3.74)	0.00	0.00	0.11	0.11	0.00	28.97	10.33	52.51	(0.02)

CLASSIFICATION OF NET INVESTMENT

DEC. 31, 2007

(millions of dollars)

		Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24	Col. 25	Col. 26	Col.27
		CUSTOMER RELATED INVESTMENTS					NUMBER OF CUSTOMERS					
Item No.	Description	Meters	Sales Stations	Services	Customer Plant	Rentals	Commercial/ Industrial	Contracts	Direct Purchase	Total	Readings Processed	Entrac
	GAS SUPPLY											
1.	Gas Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION											
3.	Mains	0.00	0.00	0.00	37.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Distribution Reg.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER											
5.	Sales Station	0.00	8.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	9.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	0.00	0.00	98.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	0.00	0.00	0.00	0.00	(0.57)	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.51	0.00	0.00
10.	Customer Accounting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(9.64)	0.00	0.00
11.	**Sub-total**	9.77	8.27	98.62	37.90	(0.57)	0.00	0.00	0.00	(9.13)	0.00	0.00
12.	Unidentifiable	0.28	0.10	1.33	0.51	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00
13	Entrac	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.98
14.	**Total Classified**	10.05	8.37	99.96	38.41	(0.57)	0.00	0.00	0.00	(9.13)	0.00	4.98

Filed: 2007-02-23
Interim Rate Order
EB-2006-0034
Exhibit G2
Tab 4
Schedule 3

CLASSIFICATION OF O&M COSTS
DEC. 31, 2007

(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
				GAS SUPPLY									
				PRODUCT COSTS				LOAD BALANCING			STORAGE COSTS		
Item No.	Description	Total	Specific Classes	Winter Commodity	Annual Commodity	System Gas	Bad Debt Commodity	Peak	Seasonal	Transportation Annual	Deliverability	Space	Winter
	GAS SUPPLY												
1.1	Gas Purchased	2,066.26	0.00	0.00	1,605.90	0.00	0.00	7.64	5.45	432.53	0.00	0.00	0.00
1.2	Stored Gas	131.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.37	67.06	0.00
1.3	A&G	12.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	0.88	0.00	0.00	0.00	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	1.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.	Total Gas Supply	2,212.92	0.00	0.00	1,605.90	0.88	0.00	7.64	5.45	432.53	64.37	67.06	0.00
	DISTRIBUTION												
	OPERATING COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.1	Chart Processing	3.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	District Stations	2.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	49.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Gas Dispatched	5.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
2.5	Dist. System Reg.	0.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	2.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.7	Other Meters	11.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.8	Instruments	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	16.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.10	Structures	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Total Distribution Costs	95.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER SERVICE												
	OPERATING COSTS												
3.1	Heating Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Appliance Inspection	2.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.3	Locks/Unlocks/Exchanges	12.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.4	JC Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.5	JC Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
3.7	Rentals	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.8	Service Lines	4.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Customer Service	19.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SALES/MARKETING												
4.1	Residential	7.15	7.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	3.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	4.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.4	Residential/Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	General Promotion	5.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	1.83	1.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	4.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	20.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	8.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	55.07	8.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING												
5.1	Billing	70.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.2	Enquiry	34.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.3	Readings	11.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.4	Credit	22.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Uncollectibles	18.03	0.00	0.00	0.00	0.00	9.70	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	157.07	0.00	0.00	0.00	0.00	9.70	0.00	0.00	0.00	0.00	0.00	0.00
6.	**Total O&M**	2,539.64	8.98	0.00	1,605.90	0.88	9.70	7.64	5.45	432.53	64.37	67.06	0.00
7.	Deferred Taxes	9.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Fixed Financing Costs	1.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	**Total O&M Expense**	2,550.14	8.98	0.00	1,605.90	0.88	9.70	7.64	5.45	432.53	64.37	67.06	0.00

CLASSIFICATION OF O&M COSTS
DEC. 31, 2007
(millions of dollars)

Item No.	Description	Col. 13 DISTRIBUTION COSTS TP Capacity	Col. 14 HP Capacity	Col. 15 LP Capacity	Col. 16 Commodity	Col. 17 Bad Debt Distribution	Col. 18 DSM	Col. 19 CUSTOMER RELATED INVESTMENTS Meters	Col. 20 Sales Stations	Col. 21 Services	Col. 22 Customer Plant	Col. 23 Rentals
	GAS SUPPLY											
1.1	Gas Purchased	0.00	0.00	0.00	14.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.2	Stored Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.3	A&G	12.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.	Total Gas Supply	12.78	0.00	0.00	14.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION											
	OPERATING COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.1	Chart Processing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	District Stations	0.75	0.27	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	10.57	3.77	19.17	0.00	0.00	0.00	0.00	0.00	0.00	15.68	0.00
2.4	Gas Dispatched	5.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS											
2.5	Dist. System Reg.	0.24	0.09	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.16	0.00	0.00	0.00
2.7	Other Meters	0.00	0.00	0.00	0.00	0.00	0.00	11.33	0.00	0.00	0.00	0.00
2.8	Instruments	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	2.18	0.78	10.42	0.00	0.00	0.00	0.00	0.00	0.00	3.23	0.00
2.10	Structures	0.06	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.04	0.01	0.00
2.	Total Distribution Costs	22.58	4.90	31.38	0.00	0.00	0.00	11.34	2.16	0.04	18.92	0.00
	CUSTOMER SERVICE											
	OPERATING COSTS											
3.1	Heating Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Appliance Inspection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.3	Locks/Unlocks/Exchanges	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.4	JC Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.5	JC Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS											
3.7	Rentals	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.8	Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.45	0.00	0.00
3.	Total Customer Service	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.45	0.00	0.00
	SALES/MARKETING											
4.1	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.4	Residential/Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	General Promotion	5.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	0.00	0.00	0.00	0.00	0.00	20.28	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	0.00	0.00	0.00	0.00	0.00	8.16	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	5.33	0.00	0.00	0.00	0.00	28.45	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING											
5.1	Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.2	Enquiry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.3	Readings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.4	Credit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Uncollectibles	0.00	0.00	0.00	0.00	8.33	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	0.00	0.00	0.00	0.00	8.33	0.00	0.00	0.00	0.00	0.00	0.00
6.	**Total O&M**	40.69	4.90	31.38	14.75	8.33	28.45	11.34	2.16	4.48	18.92	0.00
7.	Deferred Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Fixed Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	**Total O&M Expense**	40.69	4.90	31.38	14.75	8.33	28.45	11.34	2.16	4.48	18.92	0.00

CLASSIFICATION OF O&M COSTS
DEC. 31, 2007

(millions of dollars)

		Col. 24	Col. 25	Col. 26	Col. 27	Col. 28	Col. 29	Col.30
		NUMBER OF CUSTOMERS						
Item No.	Description	Commercial/ Industrial	Contracts	Direct Purchase	Total	Readings Processed	Deferred Taxes	Fixed Financing
	GAS SUPPLY							
1.1	Gas Purchased	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.2	Stored Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.3	A&G	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	0.00	0.00	1.56	0.00	0.00	0.00	0.00
1.	Total Gas Supply	0.00	0.00	1.56	0.00	0.00	0.00	0.00
	DISTRIBUTION							
	OPERATING COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.1	Chart Processing	0.00	0.00	0.00	0.00	3.70	0.00	0.00
2.2	District Stations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Gas Dispatched	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS							
2.5	Dist. System Reg.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.7	Other Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.8	Instruments	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.10	Structures	0.00	0.00	0.00	0.13	0.00	0.00	0.00
2.	Total Distribution Costs	0.00	0.00	0.00	0.13	3.70	0.00	0.00
	CUSTOMER SERVICE							
	OPERATING COSTS							
3.1	Heating Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Appliance Inspection	0.00	0.00	0.00	2.77	0.00	0.00	0.00
3.3	Locks/Unlocks/Exchanges	0.00	0.00	0.00	12.22	0.00	0.00	0.00
3.4	JC Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.5	JC Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS							
3.7	Rentals	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.8	Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Customer Service	0.00	0.00	0.00	14.99	0.00	0.00	0.00
	SALES/MARKETING							
4.1	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	3.37	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	4.78	0.00	0.00	0.00	0.00	0.00	0.00
4.4	Residential/Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	General Promotion	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	0.00	4.16	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	8.14	4.16	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING							
5.1	Billing	0.00	0.00	0.00	70.46	0.00	0.00	0.00
5.2	Enquiry	0.00	0.00	0.00	34.46	0.00	0.00	0.00
5.3	Readings	0.00	0.00	0.00	0.00	11.95	0.00	0.00
5.4	Credit	0.00	0.00	0.00	22.16	0.00	0.00	0.00
5.5	Uncollectibles	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	0.00	0.00	0.00	127.09	11.95	0.00	0.00
6.	**Total O&M**	8.14	4.16	1.56	142.21	15.64	0.00	0.00
7.	Deferred Taxes	0.00	0.00	0.00	0.00	0.00	9.20	0.00
8.	Fixed Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	1.30
9.	**Total O&M Expense**	8.14	4.16	1.56	142.21	15.64	9.20	1.30

ALLOCATION OF RATE BASE

DEC. 31, 2007

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 RATE BASE	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 305	Col. 15 FACTORS EXHIBIT G2.6.3 *
	SUPPLY COST															
	PRODUCT COSTS															
1.1	Annual Commodity	17.18	10.00	5.23	0.02	0.79	0.18	0.15	0.00	0.02	0.15	0.21	0.43	0.00	0.00	1.1
1	Total Gas Cost	17.18	10.00	5.23	0.02	0.79	0.18	0.15	0.00	0.02	0.15	0.21	0.43	0.00	0.00	
	PIPELINE TRANS.															
2.1	Peak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.1
2.2	Seasonal	617.35	288.36	206.31	0.00	74.61	10.33	3.74	0.00	0.00	10.88	15.45	7.68	0.00	0.00	3.2
2.3	Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.2
2	Total Pipeline Trans. Cost	617.35	288.36	206.31	0.00	74.61	10.33	3.74	0.00	0.00	10.88	15.45	7.68	0.00	0.00	
	FACILITIES' COSTS															
	STORAGE FACILITIES															
3.1	Deliverability	12.75	6.28	4.65	0.00	1.55	0.09	0.01	0.00	0.00	0.00	0.00	0.17	0.00	0.00	3.1
3.2	Space	13.28	6.20	4.44	0.00	1.60	0.22	0.08	0.00	0.00	0.23	0.33	0.17	0.00	0.00	3.2
3	Total Storage	26.03	12.48	9.09	0.00	3.15	0.32	0.09	0.00	0.00	0.23	0.33	0.33	0.00	0.00	
	DISTRIBUTION FACILITIES															
4.1	Capacity TP	319.38	143.70	104.19	0.06	38.25	7.59	8.50	9.61	0.02	2.26	1.09	4.10	0.00	0.00	2.1
4.2	Capacity HP	113.91	54.06	39.20	0.02	14.39	2.86	2.01	0.00	0.01	0.85	0.41	0.00	0.00	0.10	2.2
4.3	Capacity LP	578.94	275.67	199.87	0.11	73.38	14.56	8.37	0.00	0.04	4.34	2.09	0.00	0.00	0.50	2.3
4.4	Commodity	0.09	0.03	0.02	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	1.3
4.5	Customer Plant	432.48	396.44	35.42	0.01	0.47	0.07	0.01	0.00	0.01	0.04	0.01	0.00	0.00	0.00	2.4
4	Total Distribution	1,444.80	869.91	378.70	0.20	126.51	25.08	18.91	9.61	0.08	7.50	3.60	4.10	0.00	0.60	
	CUSTOMER RELATED															
5.1	Meters	237.21	135.98	87.70	0.10	9.63	1.65	0.38	0.05	0.32	1.07	0.32	0.00	0.00	0.01	4.1
5.2	Sales Stations	85.97	5.62	61.34	0.07	11.00	2.78	0.60	0.00	1.20	1.44	1.88	0.00	0.00	0.06	4.2
5.3	Services	1,123.20	990.39	126.27	0.06	4.27	0.79	0.32	0.00	0.15	0.57	0.39	0.00	0.00	0.01	4.3
5.4	Rentals	2.33	0.47	1.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.4
5.5	Comm./Ind. Customers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.6
5.6	Contracts	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.7
5.7	Direct Purchase	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.11
5.8	Total Customers	(1.91)	(1.75)	(0.16)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	0.00	(0.00)	4.5
5.9	Specific Classes	7.57	2.09	0.69	4.75	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
5.10	Readings Processed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.8 & 4.9
5.11	GST Revenue	(14.53)	(8.45)	(4.43)	(0.02)	(0.67)	(0.15)	(0.13)	0.00	(0.02)	(0.13)	(0.18)	(0.36)	0.00	0.00	1.1
5	Total Customer Related	1,439.85	1,124.35	273.29	4.96	24.23	5.06	1.20	0.05	1.65	2.96	2.41	(0.36)	0.00	0.08	
6	Entrac	12.43	8.07	2.17	0.00	0.74	0.33	0.48	0.00	0.03	0.13	0.39	0.08	0.00	0.00	
7	**Total Rate Base**	3,557.65	2,313.16	874.80	5.19	230.03	41.29	24.57	9.66	1.78	21.86	22.38	12.27	0.00	0.67	

* G2.6.3 refers to Exhibit G2, Tab 6, Schedule 3.

ALLOCATION OF RETURN & TAXES
December 31, 2007

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 RATE BASE	Col. 2 RETURN & TAXES	Col. 3 RATE 1	Col. 4 RATE 6	Col. 5 RATE 9	Col. 6 RATE 100	Col. 7 RATE 110	Col. 8 RATE 115	Col. 9 RATE 125	Col. 10 RATE 135	Col. 11 RATE 145	Col. 12 RATE 170	Col. 13 RATE 200	Col. 14 RATE 300	Col. 15 RATE 305
	SUPPLY COST															
	PRODUCT COSTS															
1.1	Annual Commodity	17.18	1.47	0.86	0.45	0.00	0.07	0.02	0.01	0.00	0.00	0.01	0.02	0.04	0.00	0.00
1	Total Gas Cost	17.18	1.47	0.86	0.45	0.00	0.07	0.02	0.01	0.00	0.00	0.01	0.02	0.04	0.00	0.00
	PIPELINE TRANS.															
2.1	Peak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	Seasonal	617.35	52.85	24.69	17.66	0.00	6.39	0.88	0.32	0.00	0.00	0.93	1.32	0.66	0.00	0.00
2.3	Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Total Pipeline Trans. Cost	617.35	52.85	24.69	17.66	0.00	6.39	0.88	0.32	0.00	0.00	0.93	1.32	0.66	0.00	0.00
	FACILITIES' COSTS															
	STORAGE FACILITIES															
3.1	Deliverability	12.75	1.09	0.54	0.40	0.00	0.13	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
3.2	Space	13.28	1.14	0.53	0.38	0.00	0.14	0.02	0.01	0.00	0.00	0.02	0.03	0.01	0.00	0.00
3	Total Storage	26.03	2.23	1.07	0.78	0.00	0.27	0.03	0.01	0.00	0.00	0.02	0.03	0.03	0.00	0.00
	DISTRIBUTION FACILITIES															
4.1	Capacity TP	319.38	27.34	12.30	8.92	0.01	3.28	0.65	0.73	0.82	0.00	0.19	0.09	0.35	0.00	0.00
4.2	Capacity HP	113.91	9.75	4.63	3.36	0.00	1.23	0.24	0.17	0.00	0.00	0.07	0.04	0.00	0.00	0.01
4.3	Capacity LP	578.94	49.57	23.60	17.11	0.01	6.28	1.25	0.72	0.00	0.00	0.37	0.18	0.00	0.00	0.04
4.4	Commodity	0.09	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	Customer Plant	432.48	37.03	33.94	3.03	0.00	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Total Distribution	1,444.80	123.70	74.48	32.42	0.02	10.83	2.15	1.62	0.82	0.01	0.64	0.31	0.35	0.00	0.05
	CUSTOMER RELATED															
5.1	Meters	237.21	20.31	11.64	7.51	0.01	0.82	0.14	0.03	0.00	0.03	0.09	0.03	0.00	0.00	0.00
5.2	Sales Stations	85.97	7.36	0.48	5.25	0.01	0.94	0.24	0.05	0.00	0.10	0.12	0.16	0.00	0.00	0.00
5.3	Services	1,123.20	96.16	84.79	10.81	0.00	0.37	0.07	0.03	0.00	0.01	0.05	0.03	0.00	0.00	0.00
5.4	Rentals	2.33	0.20	0.04	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Comm./Ind. Customers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.6	Contracts	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.7	Direct Purchase	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.8	Total Customers	(1.91)	(0.16)	(0.15)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	0.00	(0.00)
5.9	Specific Classes	7.57	0.65	0.18	0.06	0.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.10	Readings Processed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.11	GST Revenue	(14.53)	(1.24)	(0.72)	(0.38)	(0.00)	(0.06)	(0.01)	(0.01)	0.00	(0.00)	(0.01)	(0.02)	(0.03)	0.00	0.00
5	Total Customer Related	1,439.85	123.27	96.26	23.40	0.42	2.07	0.43	0.10	0.00	0.14	0.25	0.21	(0.03)	0.00	0.01
6	Entrac	12.43	1.06	0.69	0.19	0.00	0.06	0.03	0.04	0.00	0.00	0.01	0.03	0.01	0.00	0.00
7	**Total Facilities**	3,557.65	304.59	198.04	74.90	0.44	19.69	3.53	2.10	0.83	0.15	1.87	1.92	1.05	0.00	0.06

ALLOCATION OF TOTAL COST OF SERVICE
December 31, 2007

(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	ALLOCATION FACTORS
ITEM NO.	DESCRIPTION	O&M COSTS	NET INV. COSTS	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 305	DIRECT PURCHASE	EXHIBIT G2.6.3 *
	SUPPLY COSTS																		
	PRODUCT COSTS																		
1.1	Annual Commodity	1,605.90	0.04	1,605.94	934.35	489.19	1.83	74.00	16.96	14.12	0.00	1.77	13.94	19.46	40.31	0.00	0.00	0.00	1.1
1.2	Bad Debt Commodity	9.70	0.00	9.70	4.72	4.82	0.00	0.12	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00	
1.3	System Gas Fee	0.88	0.00	0.88	0.51	0.27	0.00	0.04	0.01	0.01	0.00	0.00	0.01	0.01	0.02	0.00	0.00	0.00	1.5
1	Total Gas Cost	1,616.48	0.04	1,616.52	939.58	494.28	1.83	74.16	16.97	14.13	0.00	1.77	13.99	19.47	40.33	0.00	0.00	0.00	
	PIPELINE TRANS.																		
2.1	Peak	7.64	0.00	17.50	8.62	6.38	0.00	2.12	0.13	0.02	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00	3.1
2.2	Seasonal	5.45	1.35	6.81	3.18	2.28	0.00	0.82	0.11	0.04	0.00	0.00	0.12	0.17	0.08	0.00	0.00	0.00	3.2
2.3	Annual - Transportation	432.53	0.00	432.53	165.11	115.90	0.27	51.16	22.88	33.43	0.00	2.04	9.27	26.91	5.56	0.00	0.00	0.00	1.2
2.4	Seasonal Credit	0.00	0.00	(9.86)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.94)	(8.80)	(0.12)	0.00	0.00	0.00	
2.5	TS Revenue	0.00	(3.74)	(3.74)	(1.43)	(1.00)	(0.00)	(0.44)	(0.20)	(0.29)	0.00	(0.02)	(0.08)	(0.23)	(0.05)	0.00	0.00	0.00	1.2
2	Total Pipeline Trans. Cost	445.62	(2.39)	443.23	175.48	123.55	0.27	53.66	22.93	33.19	0.00	2.03	8.37	18.05	5.70	0.00	0.00	0.00	
	FACILITIES' COSTS																		
	STORAGE FACILITIES																		
3.1	Deliverability	64.37	0.11	64.95	31.99	23.68	0.00	7.88	0.47	0.07	0.00	0.00	0.00	0.00	0.85	0.00	0.00	0.00	3.1
3.2	Space	67.06	0.11	67.17	31.37	22.45	0.00	8.12	1.12	0.41	0.00	0.00	1.18	1.68	0.84	0.00	0.00	0.00	3.2
3.3	Seasonal Credit	0.00	0.00	(0.47)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.47)	0.00	0.00	0.00	0.00	0.00	0.00	
3	Total Storage	131.43	0.22	131.65	63.36	46.13	0.00	16.00	1.60	0.47	0.00	(0.47)	1.18	1.68	1.69	0.00	0.00	0.00	
	DISTRIBUTION FACILITIES																		
4.1	Capacity TP	40.69	28.97	69.66	31.34	22.73	0.01	8.34	1.66	1.85	2.10	0.00	0.49	0.24	0.90	0.00	0.00	0.00	2.1
4.2	Capacity HP	4.90	10.33	15.24	7.23	5.24	0.00	1.92	0.38	0.27	0.00	0.00	0.11	0.05	0.00	0.00	0.01	0.00	2.2
4.3	Capacity LP	31.38	52.51	83.90	39.95	28.96	0.02	10.63	2.11	1.21	0.00	0.01	0.63	0.30	0.00	0.00	0.07	0.00	2.3
4.4	Commodity	14.75	(0.02)	14.73	5.61	3.94	0.01	1.74	0.78	1.14	0.00	0.07	0.31	0.91	0.19	0.00	0.04	0.00	1.3
4.5	Bad Debt Distribution	8.33	0.00	8.33	4.00	4.13	0.00	0.15	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	
4.6	Customer Plant	18.92	38.41	57.33	52.56	4.70	0.00	0.06	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	2.4
4.7	DSM - Program	20.28	0.00	20.28	10.28	1.90	0.00	3.60	0.90	0.94	0.00	0.00	0.84	1.83	0.00	0.00	0.00	0.00	
4.8	DSM - General	8.16	0.00	8.16	2.47	1.08	0.00	2.05	0.51	0.53	0.00	0.00	0.48	1.04	0.00	0.00	0.00	0.00	
4	Total Distribution	147.43	130.21	277.64	153.44	72.68	0.04	28.50	6.34	5.94	2.10	0.09	2.92	4.38	1.08	0.00	0.12	0.00	
	CUSTOMER RELATED																		
5.1	Meters	11.34	10.05	21.39	12.26	7.91	0.01	0.87	0.15	0.03	0.00	0.03	0.10	0.03	0.00	0.00	0.00	0.00	4.1
5.2	Sales Stations	2.16	8.37	10.53	0.69	7.51	0.01	1.35	0.34	0.07	0.00	0.15	0.18	0.23	0.00	0.00	0.01	0.00	4.2
5.3	Services	4.48	99.96	104.44	92.09	11.74	0.01	0.40	0.07	0.03	0.00	0.01	0.05	0.04	0.00	0.00	0.00	0.00	4.3
5.4	Rentals	0.00	(0.57)	(0.57)	(0.11)	(0.45)	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.4
5.5	Comm./Ind. Customers	8.14	0.00	8.14	0.00	8.00	0.00	0.11	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	4.6
5.7	Direct Purchase	1.56	0.00	1.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.56	4.11
5.8	Total Customers	142.21	(9.13)	133.08	121.99	10.90	0.00	0.15	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	4.5
5.9	Specific Classes	8.98	0.49	9.47	7.40	0.96	0.74	0.00	0.19	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
5.10	Readings Processed	15.64	0.00	15.64	11.00	1.95	0.01	2.03	0.30	0.06	0.00	0.04	0.20	0.06	0.00	0.00	0.00	0.00	4.8 & 4.9
5.11	Deferred Tax	9.20	0.00	9.20	5.98	2.26	0.01	0.59	0.11	0.06	0.02	0.00	0.06	0.06	0.03	0.00	0.00	0.00	5
5.12	Financing Costs	1.30	0.00	1.30	0.85	0.32	0.00	0.08	0.02	0.01	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	5
5.13	Entrac	0.00	4.98	4.98	3.23	0.87	0.00	0.30	0.13	0.19	0.00	0.01	0.05	0.16	0.03	0.00	0.00	0.00	
5	Total Customer Related	209.18	114.15	323.33	255.37	51.98	0.79	9.08	1.80	0.76	0.04	0.31	0.94	0.63	0.07	0.00	0.01	1.56	
6.1	Return	216.15	0.00	216.15	140.54	53.15	0.32	13.98	2.51	1.49	0.59	0.11	1.33	1.36	0.75	0.00	0.04	0.00	5
6.2	Taxes	88.44	0.00	88.44	57.51	21.75	0.13	5.72	1.03	0.61	0.24	0.04	0.54	0.56	0.30	0.00	0.02	0.00	5
6	Return and Taxes	304.59	0.00	304.59	198.04	74.90	0.44	19.69	3.53	2.10	0.83	0.15	1.87	1.92	1.05	0.00	0.06	0.00	
7	Total Facilities	792.63	244.58	1,037.21	670.22	245.68	1.28	73.28	13.27	9.28	2.96	0.08	6.91	8.61	3.89	0.00	0.20	1.56	
8	**Total Cost of Service**	2,854.73	242.23	3,096.96	1,785.28	863.51	3.38	201.10	53.16	56.60	2.96	3.87	29.27	46.13	49.93	0.00	0.20	1.56	

RATE BASE
FUNCTIONALIZATION FACTORS
DECEMBER 31, 2007

Item No.		Col. 1 Total	Col. 2 Gas Supply	Col. 3 Storage	Col. 4 Sales Stations	Col. 5 Distribution Measurement	Col. 6 Services	Col. 7 Mains	Col. 8 Meters	Col. 9 Rental Equipment	Col. 10 Sales Promotion	Col. 11 Customer Accounting	Col. 12 Unidenti-fiable	Col. 13 Entrac
	Gas Supply													
1.1	Gas Supply	1.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Distribution Plant													
2.1	Land (incl offers to buy)	1.000	0.010	0.000	0.005	0.002	0.119	0.096	0.002	0.000	0.161	0.426	0.179	0.000
2.2	Structures & Improvements	1.000	0.010	0.000	0.005	0.002	0.119	0.096	0.002	0.000	0.161	0.426	0.179	0.000
2.3	Mains	1.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000
2.4	Meas. Reg. & Telemtrng	1.000	0.000	0.000	0.532	0.468	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2.5	Services	1.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2.6	Meters	1.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000
	General Plant													
3.1	Land (incl offers to buy)	1.000	0.000	0.000	0.000	0.000	0.336	0.045	0.000	0.000	0.126	0.353	0.140	0.000
3.2	Structures & Improvements	1.000	0.000	0.000	0.000	0.000	0.336	0.045	0.000	0.000	0.126	0.353	0.140	0.000
3.3	Office Furniture & Equip.	1.000	0.001	0.001	0.001	0.123	0.161	0.200	0.046	0.017	0.024	0.031	0.394	0.000
3.4	Transportation Equipment	1.000	0.000	0.000	0.000	0.002	0.297	0.669	0.000	0.000	0.033	0.000	0.000	0.000
3.5	Heavy Work Equipment	1.000	0.000	0.000	0.000	0.002	0.297	0.669	0.000	0.000	0.033	0.000	0.000	0.000
3.6	Tools & Work Equip.	1.000	0.000	0.000	0.000	0.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
3.7	Rental Equip.	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000
3.8	Communication Equip.	1.000	0.014	0.000	0.008	0.283	0.086	0.125	0.000	0.001	0.094	0.171	0.218	0.000
3.9	Compressors	1.000	0.000	0.000	0.000	0.002	0.297	0.669	0.000	0.000	0.033	0.000	0.000	0.000
3.10	Computer Equip.	1.000	0.024	0.003	0.023	0.085	0.161	0.261	0.085	0.002	0.009	0.231	0.116	0.000
3.11	S.I.M	1.000	0.037	0.000	0.026	0.023	0.154	0.198	0.004	0.040	0.051	0.062	0.405	0.000
3.12	Entrac	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000
4.	Other Plant	1.000	0.000	0.000	0.000	0.000	0.436	0.564	0.000	0.000	0.000	0.000	0.000	0.000
5.	Plant Held for Future Use	1.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

WORKING CAPITAL AND
NET INVESTMENT
FUNCTIONALIZATION FACTORS
DECEMBER 31, 2007

Item No.		Col. 1 Total	Col. 2 Gas Supply	Col. 3 Storage	Col. 4 Sales Stations	Col. 5 Distribution Measurement	Col. 6 Services	Col. 7 Mains	Col. 8 Meters	Col. 9 Rental Equipment	Col. 10 Sales/ Marketing	Col. 11 Customer Accounting	Col. 12 Unidenti- fiable	Col. 13 GST Revenue
1.	**Prepaid Expenses**	1.000	0.000	0.000	0.000	0.000	0.123	0.123	0.000	0.000	0.009	0.000	0.746	0.000
	Materials & Supplies													
2.1	Pipe	1.000	0.000	0.000	0.000	0.000	0.227	0.773	0.000	0.000	0.000	0.000	0.000	0.000
2.2	Tools	1.000	0.000	0.000	0.000	0.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
2.3	Construction Supplies	1.000	0.000	0.000	0.000	0.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
	Net Investments													
3.	Municipal Taxes	1.000	0.001	0.000	0.004	0.004	0.314	0.626	0.000	0.000	0.011	0.028	0.012	0.000
4.	Capital Taxes	1.000	0.001	0.000	0.004	0.004	0.314	0.626	0.000	0.000	0.011	0.028	0.012	0.000

CLASSIFICATION OF GAS COSTS TO OPERATIONS

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
		System Commodity			Load Balancing							
					Storage			Pipeline				
Item No.	Description	Annual Volumes (10^3m^3)	Variable Unit Rate $/($10^3m^3$)	Variable Cost $(000)	Deliver-ability $(000)	Seasonal Space $(000)	Winter $(000)	Peak $(000)	Seasonal $(000)	Annual $(000)	Dist'n. Commodity $(000)	Total $(000)
	Purchases and Receipts											
1.1	Long-Term	1,460.1	338.894	494.8	0.0	0.0	0.0	0.0	0.0	6.8	0.0	501.6
1.2	Western Buy/Sell	8,628.7	338.894	2,924.2	0.0	0.0	0.0	0.0	0.0	37.6	0.0	2,961.8
1.3	Ontario Buy.Sell	0.0	338.894	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.4	Short-Term Annual	0.0	338.894	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.5	Short-Term Peak	43,660.0	338.894	14,796.1	0.0	0.0	0.0	7,757.8	0.0	0.0	0.0	22,554.0
1.6	Discretionary Western & US	4,264,402.2	338.894	1,445,180.3	0.0	0.0	0.0	0.0	0.0	37,886.5	0.0	1,483,066.8
1.7	Discretionary - Ontario	594,009.4	338.894	201,306.2	0.0	0.0	0.0	0.0	5,538.6	8,296.4	0.0	215,141.2
1.	Total Purchases & Receipts	4,912,160.4	338.894	1,664,701.7	0.0	0.0	0.0	7,757.8	5,538.6	46,227.2	0.0	1,724,225.3
	Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1	TCPL FT-Demand System	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	280,676.8	0.0	280,676.8
2.2	TCPL FT-Winter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.3	Alliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37,992.1	0.0	37,992.1
2.4	Vector	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48,984.1	0.0	48,984.1
2.5	Union - M13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.6	U.S. Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.7	Nova	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,658.0	0.0	1,658.0
2.8	Michcon/ANR/Link	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,166.0	0.0	1,166.0
2.	Total Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	370,477.0	0.0	370,477.0
	Other Costs											
3.1	Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22,980.0	0.0	22,980.0
3.2	Delivery Pressure Charge	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.3	Upstream Differential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	Total Other Variable Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22,980.0	0.0	22,980.0
4.	**Total Delivered Supply**	4,912,160.4	0.0	1,664,701.7	0.0	0.0	0.0	7,757.8	5,538.6	439,684.1	0.0	2,117,682.2
5.	**Storage Fluctuation**	(110,159.6)	338.894	(37,332.4)	0.0	0.0	0.0	(79.5)	(56.8)	(4,506.4)	0.0	(41,975.1)
6.	**Gas Costs to Operations**	4,802,000.8	0.0	1,627,369.3	0.0	0.0	0.0	7,678.3	5,481.8	435,177.7	0.0	2,075,707.1
7.	**Storage and Transportation**	0.0	0.0	0.0	63,858.9	66,520.6	0.0	0.0	0.0	0.0	0.0	130,379.5
8.	**Gas Costs-Storage & Trans.**	4,802,000.8	0.0	1,627,369.3	63,858.9	66,520.6	0.0	7,678.3	5,481.8	435,177.7	0.0	2,206,086.6
9.1	UUF Adjustment			(13,415.7)	0.0	0.0	0.0	(22.7)	(16.2)	(1,288.7)	14,743.4	0.0
9.2	LUF Adjustment			(8,053.3)	0.0	0.0	0.0	(15.5)	(11.1)	(975.0)	0.0	(9,054.8)
9.3	Other Costs			0.0	0.0	0.0	0.0	0.0	0.0	(388.7)	0.0	(388.7)
9.	**Total Classified Costs**			1,605,900.3	63,858.9	66,520.6	0.0	7,640.1	5,454.5	432,525.3	14,743.4	2,196,643.1
	GAS COSTS											
10.1	Classification Factors			1,605,900.3	0.0	0.0	0.0	7,640.1	5,454.5	432,525.3	14,743.4	2,066,263.6
10.2	Classification Percentages			77.720%	0.000%	0.000%	0.000%	0.370%	0.264%	20.933%	0.714%	100.000%
	STORAGE											
11.1	Classification Factors				63,858.9	66,520.6	0.0	0.0	0.0	0.0	0.0	130,379.5
11.2	Classification Percentages				48.979%	51.021%	0.000%	0.000%	0.000%	0.000%	0.000%	100.000%

CLASSIFICATION OF
STORAGE AND TRANSPORTATION

($000)

Item No.	Description	Col. 1 Tecumseh O&M	Col. 2 Annual Cost	Col. 3 Deliver-ability	Col. 4 Seasonal Space	Col. 5 Winter	Col. 6 Annual Commodity
	TECUMSEH						
	TRANSMISSION						
1.1	Annual Demand	5,299.5	5,299.5	0.0	5,299.5	0.0	0.0
1.2	Daily Demand	7,956.1	7,956.1	7,956.1	0.0	0.0	0.0
1.3	In/out	7,599.4	7,599.4	0.0	7,599.4	0.0	0.0
1.4	Fuel	6,361.3	6,361.3	0.0	6,361.3	0.0	0.0
1.5	Transactional Services Revenues	(2,363.1)	(2,363.1)	(1,417.9)	(945.2)	0.0	0.0
1.	Total Transmission	24,853.3	24,853.3	6,538.2	18,315.0	0.0	0.0
	STORAGE						
2.1	Annual Demand	6,209.7	6,209.7	0.0	6,209.7	0.0	0.0
2.2	Daily Demand	9,353.2	9,353.2	9,353.2	0.0	0.0	0.0
2.3	In/out	3,002.4	3,002.4	0.0	3,002.4	0.0	0.0
2.4	Transactional Services Revenues	(2,004.9)	(2,004.9)	(1,202.9)	(802.0)	0.0	0.0
2.	Total Storage	16,560.5	16,560.5	8,150.3	8,410.2	0.0	0.0
3.	Total Tecumseh	41,413.7	41,413.7	14,688.5	26,725.2	0.0	0.0
	UNION GAS						
	STORAGE						
4.1	Space		2,722.8	0.0	2,722.8	0.0	0.0
4.2	Peak		4,032.2	4,032.2	0.0	0.0	0.0
4.3	Injection		79.0	0.0	79.0	0.0	0.0
4.4	Withdrawal		74.2	0.0	74.2	0.0	0.0
	Chatham D		125.6	0.0	125.6	0.0	0.0
4.	Total Storage		7,033.8	4,032.2	3,001.6	0.0	0.0
	TRANSMISSION						
5.1	Demand with comp.		52,133.5	26,874.0	25,259.6	0.0	0.0
5.2	Company Production M13		0.0	0.0	0.0	0.0	0.0
5.3	US Trns. C1		0.0	0.0	0.0	0.0	0.0
5.4	Fuel		24,476.6	12,617.3	11,859.3	0.0	0.0
5.5	Interruptible Margin Rebate		(730.3)	(376.5)	(353.8)	0.0	0.0
5.	Total Transportation		75,879.8	39,114.8	36,765.1	0.0	0.0
6.	SNG Premium		0.0	0.0	0.0	0.0	0.0
	DEHYDRATION						
7.1	Demand		739.5	739.5	0.0	0.0	0.0
7.2	Commodity		28.7	0.0	28.7	0.0	0.0
7.	Total Dehydration		768.2	739.5	28.7	0.0	0.0
8.	Total Union		83,681.8	43,886.5	39,795.4	0.0	0.0
	TRANSCANADA						
9.1	STS and Other		5,283.9	5,283.9	0.0	0.0	0.0
9.	Total TransCanada		5,283.9	5,283.9	0.0	0.0	0.0
10.	**TOTAL STORAGE & TRANSP.**	41,413.7	130,379.5	63,858.9	66,520.6	0.0	0.0
11.	**Less Union M13**		0.0	0.0	0.0	0.0	0.0
12.	**Less Union C1**		0.0	0.0	0.0	0.0	0.0
13.	**COST TO OPERATIONS**	41,413.7	130,379.5	63,858.9	66,520.6	0.0	0.0

CLASSIFICATION OF TRANSPORTATION COSTS

($000)

Item No.	Description	Col. 1 Total	Col. 2 Peak	Col. 3 Seasonal	Col. 4 Annual Delivery	Col. 5 Annual Commodity
	FT TCPL					
1.1	Demand	261,258.5	0.0	0.0	261,258.5	0.0
1.2	Commodity	19,418.3	0.0	0.0	0.0	19,418.3
1.3	Winter	0.0	0.0	0.0	0.0	0.0
	Alliance					
2.1	Demand	37,992.1	0.0	0.0	37,992.1	0.0
2.2	Commodity	0.0	0.0	0.0	0.0	0.0
3	**Vector Demand**	48,984.1	0.0	0.0	48,984.1	0.0
4	**US Transportation**	0.0	0.0	0.0	0.0	0.0
5	**NOVA Demand**	1,658.0	0.0	0.0	1,658.0	0.0
6	**Michcon/ANR/Link**	1,166.0	0.0	0.0	1,166.0	0.0
	OTHER					
7.1	Fuel	22,980.0	0.0	0.0	0.0	22,980.0
7.2	Delivery Pr. Diff	0.0	0.0	0.0	0.0	0.0
7.3	Upstream Diff.	0.0	0.0	0.0	0.0	0.0
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8	**Total**	393,457.0	0.0	0.0	351,058.7	42,398.3

ALLOCATION FACTORS
DEC. 31, 2007

	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
	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	RATE 305	RATE 315	Direct Purchase
COMMODITY RESPONSIBILITY																
1.1 Annual Sales	4,738.7	2,757.0	1,443.5	5.4	218.3	50.0	41.7	0.0	5.2	41.1	57.4	118.9	0.0	0.0	0.0	0.0
1.2 Bundled Annual Deliveries	11,726.3	4,476.3	3,142.1	7.4	1,387.0	620.4	906.2	0.0	55.4	251.2	729.6	150.7	0.0	0.0	0.0	0.0
1.3 Total Annual Deliveries	11,757.6	4,476.3	3,142.1	7.4	1,387.0	620.4	906.2	0.0	55.4	251.2	729.6	150.7	0.0	31.2	0.0	0.0
1.4 Bundled Peak Delivery	96,368.8	44,705.5	32,413.6	18.4	11,900.4	2,360.9	2,643.7	0.0	6.9	704.6	338.4	1,276.5	0.0	0.0	0.0	0.0
1.5 System Gas Sales	4,738.7	2,757.0	1,443.5	5.4	218.3	50.0	41.7	0.0	5.2	41.1	57.4	118.9	0.0	0.0	0.0	0.0
DISTRIBUTION CAPACITY RESPONSIBILITY																
2.1 Delivery Demand TP	99,359.1	44,705.5	32,413.6	18.4	11,900.4	2,360.9	2,643.7	2,990.3	6.9	704.6	338.4	1,276.5	0.0	0.0	0.0	0.0
2.2 Delivery Demand HP	94,195.1	44,705.5	32,413.6	18.4	11,900.4	2,360.9	1,665.7	0.0	6.9	704.6	338.4	0.0	0.0	80.9	0.0	0.0
2.3 Delivery Demand LP	93,887.1	44,705.5	32,413.6	18.4	11,900.4	2,360.9	1,357.6	0.0	6.9	704.6	338.4	0.0	0.0	80.9	0.0	0.0
2.4 Cust. Rel Plant	1,823,258	1,671,317	149,319	32	1,996	287	62	1	37	171	34	1	0	1	0	0.0
STORAGE RESPONSIBILITY																
3.1 Deliverability	48.5	23.9	17.7	0.0	5.9	0.4	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0
3.2 Space	2,770.3	1,294.0	925.8	0.0	334.8	46.3	16.8	0.0	0.0	48.8	69.3	34.5	0.0	0.0	0.0	0.0
CUSTOMER RESPONSIBILITY																
4.1 Meters	345,100.0	197,830.4	127,593.8	140.3	14,015.8	2,394.1	554.4	70.0	462.5	1,560.8	464.2	0.0	0.0	13.7	0.0	0.0
4.2 Sales Stations	146,528.9	9,583.1	104,539.7	125.8	18,741.3	4,730.8	1,018.3	0.0	2,042.8	2,454.8	3,198.2	0.0	0.0	94.1	0.0	0.0
4.3 Services	1,786,400.0	1,575,159.1	200,824.4	91.9	6,785.8	1,263.2	501.2	0.0	233.4	909.3	613.6	0.0	0.0	18.0	0.0	0.0
4.4 Rental Equipment	0.3	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4.5 Total Customer Count	1,823,258	1,671,317	149,319	32	1,996	287	62	1	37	171	34	1	0	1	0	0.0
4.6 Comm/Ind. Customer Count	151,941	0	149,319	32	1,996	287	62	1	37	171	34	1	0	1	0	0.0
4.7 Contracts	2,590	0	0	0	1,996	287	62	1	37	171	34	1	0	1	0	0.0
4.8 Chart Readings non AMR per Year	59,996	0	59,348	648	0	0	0	0	0	0	0	0	0	0	0	0.0
4.9 Chart Readings AMR per Year	3,714	0	1,009	9	2,042	297	62	1	38	199	56	0	0	1	0	0.0
4.10 Meter Readings per Year	10,894,986	10,027,902	867,084	0	0	0	0	0	0	0	0	0	0	0	0	0.0
4.11 Direct Purchase Customers	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.0
4.12 Asset Usage Allocator	93.4	71.1	16.4	0.0	3.2	0.9	0.7	0.0	0.0	0.5	0.3	0.2	0.0	0.0	0.0	0.0
5. Rate Base	3,557.6	2,313.2	874.8	5.2	230.0	41.3	24.6	9.7	1.8	21.9	22.4	12.3	0.0	0.7	0.0	0.0

ALLOCATION PERCENTAGES
DEC. 31, 2007

	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	RATE 305	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	1.0000	0.5818	0.3046	0.0011	0.0461	0.0106	0.0088	0.0000	0.0011	0.0087	0.0121	0.0251	0.0000	0.0000	0.0000
1.2 Bundled Annual Deliveries	1.0000	0.3817	0.2680	0.0006	0.1183	0.0529	0.0773	0.0000	0.0047	0.0214	0.0622	0.0128	0.0000	0.0000	0.0000
1.3 Total Annual Deliveries	1.0000	0.3807	0.2672	0.0006	0.1180	0.0528	0.0771	0.0000	0.0047	0.0214	0.0621	0.0128	0.0000	0.0027	0.0000
1.4 Bundled Peak Delivery	1.0000	0.4639	0.3363	0.0002	0.1235	0.0245	0.0274	0.0000	0.0001	0.0073	0.0035	0.0132	0.0000	0.0000	0.0000
1.5 System Gas Sales	1.0000	0.5818	0.3046	0.0011	0.0461	0.0106	0.0088	0.0000	0.0011	0.0087	0.0121	0.0251	0.0000	0.0000	0.0000
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	1.0000	0.4499	0.3262	0.0002	0.1198	0.0238	0.0266	0.0301	0.0001	0.0071	0.0034	0.0128	0.0000	0.0000	0.0000
2.2 Delivery Demand HP	1.0000	0.4746	0.3441	0.0002	0.1263	0.0251	0.0177	0.0000	0.0001	0.0075	0.0036	0.0000	0.0000	0.0009	0.0000
2.3 Delivery Demand LP	1.0000	0.4762	0.3452	0.0002	0.1268	0.0251	0.0145	0.0000	0.0001	0.0075	0.0036	0.0000	0.0000	0.0009	0.0000
2.4 Cust. Rel Plant	1.0000	0.9167	0.0819	0.0000	0.0011	0.0002	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	0.4925	0.3646	0.0000	0.1214	0.0073	0.0010	0.0000	0.0000	0.0000	0.0000	0.0131	0.0000	0.0000	0.0000
3.2 Space	1.0000	0.4671	0.3342	0.0000	0.1209	0.0167	0.0061	0.0000	0.0000	0.0176	0.0250	0.0124	0.0000	0.0000	0.0000
CUSTOMER RESPONSIBILITY															
4.1 Meters	1.0000	0.5733	0.3697	0.0004	0.0406	0.0069	0.0016	0.0002	0.0013	0.0045	0.0013	0.0000	0.0000	0.0000	0.0000
4.2 Sales Stations	1.0000	0.0654	0.7134	0.0009	0.1279	0.0323	0.0069	0.0000	0.0139	0.0168	0.0218	0.0000	0.0000	0.0006	0.0000
4.3 Services	1.0000	0.8818	0.1124	0.0001	0.0038	0.0007	0.0003	0.0000	0.0001	0.0005	0.0003	0.0000	0.0000	0.0000	0.0000
4.4 Rental Equipment	1.0000	0.2000	0.7999	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.5 Total Customer Count	1.0000	0.9167	0.0819	0.0000	0.0011	0.0002	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
4.6 Comm/Ind. Customer Count	1.0000	0.0000	0.9827	0.0002	0.0131	0.0019	0.0004	0.0000	0.0002	0.0011	0.0002	0.0000	0.0000	0.0000	0.0000
4.7 Contracts	1.0000	0.0000	0.0000	0.0000	0.7707	0.1108	0.0239	0.0004	0.0143	0.0660	0.0131	0.0004	0.0000	0.0004	0.0000
4.8 Chart Readings non AMR per Yea	1.0000	0.0000	0.9892	0.0108	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.9 Chart Readings AMR per Year	1.0000	0.0000	0.2717	0.0024	0.5498	0.0800	0.0167	0.0003	0.0102	0.0536	0.0151	0.0000	0.0000	0.0003	0.0000
4.10 Meter Readings per Year	1.0000	0.9204	0.0796	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.11 Separation Expense Allocator	1.0000	0.7750	0.2250	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.12 Direct Purchase Customers	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
4.13 Asset Usage Allocator	1.0000	0.7613	0.1757	0.0003	0.0346	0.0094	0.0076	0.0000	0.0003	0.0054	0.0036	0.0017	0.0000	0.0000	0.0000
5. Rate Base	1.0000	0.6502	0.2459	0.0015	0.0647	0.0116	0.0069	0.0027	0.0005	0.0061	0.0063	0.0034	0.0000	0.0002	0.0000

Allocation of DSM Program and General Costs Including Fringe Benefits and A&G

DEC. 31, 2007

(millions of dollars)

	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
DSM Program and General Costs	16.99	8.61	1.59	0.00	3.02	0.75	0.78	0.00	0.00	0.70	1.53	0.00	0.00
Fringe Benefits	1.83	0.55	0.24	0.00	0.46	0.11	0.12	0.00	0.00	0.11	0.23	0.00	0.00
A&G	4.62	2.07	0.48	0.00	0.92	0.23	0.24	0.00	0.00	0.21	0.47	0.00	0.00
Total	23.44	11.24	2.32	0.00	4.40	1.09	1.14	0.00	0.00	1.02	2.23	0.00	0.00
Breakdown of DSM Program and General Costs:													
DSM Program Costs	16.99	8.61	1.59	0.00	3.02	0.75	0.78	0.00	0.00	0.70	1.53	0.00	0.00
A&G	3.29	1.67	0.31	0.00	0.58	0.15	0.15	0.00	0.00	0.14	0.30	0.00	0.00
Total	20.28	10.28	1.90	0.00	3.60	0.90	0.94	0.00	0.00	0.84	1.83	0.00	0.00
DSM General Costs	5.01	1.51	0.66	0.00	1.26	0.31	0.33	0.00	0.00	0.29	0.64	0.00	0.00
Fringe Benefits	1.83	0.55	0.24	0.00	0.46	0.11	0.12	0.00	0.00	0.11	0.23	0.00	0.00
A&G	1.33	0.40	0.18	0.00	0.33	0.08	0.09	0.00	0.00	0.08	0.17	0.00	0.00
Total	8.16	2.47	1.08	0.00	2.05	0.51	0.53	0.00	0.00	0.48	1.04	0.00	0.00

TECUMSEH GAS
FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE
2007 TEST YEAR

($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
		FUNCTIONALIZATION					CLASSIFICATION									
							Transmission & Compression					Pool Storage Space				
Item No.	Description	Functional Allocation T/C	Pool	Net Investment Avg. of Mnthly Avg.	Transmission & Compression	Pool Storage Space	Net Investment Avg. of Mnthly Avg.			Annual Demand	Daily Demand	Net Investment Avg. of Mnthly Avg.			Annual Demand	Daily Demand
1.1	Transmission Lines	100%	0%	9,519.5	9,519.5		9,519.5	40%	60%	3,807.8	5,711.7		40%	60%	0.0	0.0
1.2	Compressor Equipment	100%	0%	54,621.6	54,621.6		54,621.6	40%	60%	21,848.6	32,773.0		40%	60%	0.0	0.0
1.3	Structures & Improvements	100%	0%	7,414.0	7,414.0		7,414.0	40%	60%	2,965.6	4,448.4		40%	60%	0.0	0.0
1.4	Office and Plant Equipment	100%	0%	1,250.1	1,250.1		1,250.1	40%	60%	500.0	750.1		40%	60%	0.0	0.0
1.5	Land	100%	0%	188.7	188.7		188.7	40%	60%	75.5	113.2		40%	60%	0.0	0.0
1.6.1	Allowance for - Mat'ls & Supplies	100%	0%	2,362.3	2,362.3		2,362.3	40%	60%	944.9	1,417.4		40%	60%	0.0	0.0
1.6.2	Working Capital - Working Cash Allow.	100%	0%	1,100.0	1,100.0		1,100.0	40%	60%	440.0	660.0		40%	60%	0.0	0.0
1.7	Provision for LUF	69%	31%		0.0	0.0	0.0	40%	60%	0.0	0.0	0.0	40%	60%	0.0	0.0
1.				76,456.2	76,456.2		76,456.2			30,582.5	45,873.7					
2.1	Field Lines	0%	100%	19,518.3		19,518.3		40%	60%	0.0	0.0	19,518.3	40%	60%	7,807.3	11,711.0
2.2	Wells	0%	100%	14,275.1		14,275.1		40%	60%	0.0	0.0	14,275.1	40%	60%	5,710.0	8,565.1
2.3	Well Equipment	0%	100%	3,638.6		3,638.6		40%	60%	0.0	0.0	3,638.6	40%	60%	1,455.4	2,183.2
2.4	Measuring & Regulating	0%	100%	8,472.1		8,472.1		40%	60%	0.0	0.0	8,472.1	40%	60%	3,388.8	5,083.3
2.5	Gas Storage Rights	0%	100%	22,708.2		22,708.2		40%	60%	0.0	0.0	22,708.2	40%	60%	9,083.3	13,624.9
2.6	Petroleum and Natural Gas Leases	0%	100%			0.0		40%	60%	0.0	0.0	0.0	40%	60%	0.0	0.0
2.7	Base Pressure Gas	0%	100%	40,767.1		40,767.1		40%	60%	0.0	0.0	40,767.1	40%	60%	16,306.8	24,460.3
2.8	Other	0%	100%			0.0	0.0	40%	60%	0.0	0.0	0.0	40%	60%	0.0	0.0
2.				109,379.4		109,379.4						109,379.4			43,751.8	65,627.6
3.	Total			185,835.6	76,456.2	109,379.4	76,456.2			30,582.5	45,873.7	109,379.4			43,751.8	65,627.6
4.	Percentage Allocation			2,369.0	41.142%	58.858%				40.000%	60.000%				40.000%	60.000%

TECUMSEH GAS
FUNCTIONAL ALLOCATION OF COST OF SERVICE
2007 TEST YEAR

Item No.		Col.1 Functional Allocation T/C	Col.2 Pool	Col.3 Utility Return & Expenses	Col.4 Transmission & Compression	Col.5 Pool Storage
RATE BASE RETURN AMOUNT				($000)	($000)	($000)
1.1	Utility Return	40%	60%	15,909.9	6,364.0	9,545.9
1.	Total Return	0%	0%	15,909.9	6,364.0	9,545.9
EXPENSES - OPERATION						
2.1.1	Labour	80%	20%	1,428.7	1,142.9	285.7
2.1.2	Supplies & Other		10%	355.0	319.5	35.5
2.1.3	Hydro	100%	0%	360.8	360.8	
2.1.4	Lease Rentals	0%	100%	1,248.7		1,248.7
2.1.5	Surface Rentals	0%	100%			
2.1.6	Provision for LUF	69%	31%	9,054.8	6,247.8	2,807.0
2.1	Subtotal			12,447.9	8,071.0	4,376.9
MAINTENANCE						
2.2.1	Company	90%	10%	1,798.1	1,618.3	179.8
2.2.2	Contractor	80%	20%	597.0	477.6	119.4
2.2	Subtotal			2,395.1	2,095.9	299.2
ADMINISTRATIVE & GENERAL						
2.3.1	General Office	80%	20%	1,975.4	1,580.3	395.1
2.3.2	Service Fees	80%	20%	1,013.0	810.4	202.6
2.3.3	Overhead Capitalized	80%	20%	(451.6)	(361.3)	(90.3)
2.3	Subtotal			2,536.8	2,029.4	507.4
DEPRECIATION AND AMORTIZATION						
2.4.1	Depreciation	47%	53%	5,301.1	2,508.5	2,792.6
2.4.2	Amortization	0%	100%	868.3		868.3
2.4	Subtotal			6,169.4	2,508.5	3,660.9
TAXES - OTHER THAN INCOME						
2.5.1	Municipal	80%	20%	1,351.0	1,080.8	270.2
2.5.2	Capital	40%	60%	505.0	202.0	303.0
2.5	Subtotal			1,856.0	1,282.8	573.2
2. TOTAL EXPENSES				25,405.3	15,987.6	9,417.6
3. REVENUE REQUIREMENT BEFORE TAXES				41,315.2	22,351.5	18,963.6

Filed: 2007-02-23
Interim Rate Order
EB-2006-0034
Exhibit G2
Tab 7
Schedule 3
Page 1 of 1

TECUMSEH GAS
CLASSIFICATION OF COST OF SERVICE
2007 TEST YEAR

($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	Col. 14
							Transmission & Compression						Pool Storage							
Item No.		Functional Allocation T/C	Pool	Utility Return & Expenses	Transmission & Compression	Storage Space	Total	Alloc'tn Ann	Dly	Annual Demand	Daily Demand	Commodity	Storage Total	Union Transfer	Net Tecumseh	Alloc'tn Ann	Dly	Annual Demand	Daily Demand	Commodity
	RATE BASE RETURN AMOUNT																			
1.1	Utility Return	40%	60%	15,909.9	6,364.0	9,545.9	6,364.0	40%	60%	2,545.6	3,818.4		9,545.9	0.0	9,545.9	40%	60%	3,818.4	5,727.6	
1.	Total Return			15,909.9	6,364.0	9,545.9	6,364.0			2,545.6	3,818.4		9,545.9	0.0	9,545.9			3,818.4	5,727.6	
	EXPENSES - OPERATION																			
2.1.1	Labour	80%	20%	1,428.7	1,142.9	285.7	1,142.9	40%	60%	457.2	685.7		285.7	16.2	269.5	40%	60%	107.8	161.7	
2.1.2	Supplies & Other	90%	10%	355.0	319.5	35.5	319.5	20%	30%	63.9	95.9	159.7	35.5	2.0	33.5	20%	30%	6.7	10.0	16.8
2.1.3	Hydro	100%	0%	360.8	360.8		360.8	20%	30%	72.2	108.2	180.4				0%	0%			
2.1.4	Lease Rentals	0%	100%	1,248.7		1,248.7		40%	60%				1,248.7		1,248.7	40%	60%	499.5	749.2	
2.1.5	Surface Rentals	0%	100%	0.0		0.0		40%	60%				0.0			40%	60%			
2.1.6	Provision for LUF	69%	31%	9,054.8	6,247.8	2,807.0	6,247.8	0%	0%			6,247.8	2,807.0	0.0	2,807.0	0%	0%			2,807.0
2.1	Subtotal			12,447.9	8,071.0	4,376.9	8,071.0			593.3	889.8	6,587.9	4,376.9	18.2	4,358.7			614.0	920.9	2,823.8
	MAINTENANCE																			
2.2.1	Company	90%	10%	1,798.1	1,618.3	179.8	1,618.3	10%	15%	161.8	242.7	1,213.8	179.8	10.2	169.6	10%	15%	17.0	25.4	127.2
2.2.2	Contractor	80%	20%	597.0	477.6	119.4	477.6	10%	15%	47.8	71.6	358.2	119.4	6.8	112.6	10%	15%	11.3	16.9	84.4
2.2	Subtotal			2,395.1	2,095.9	299.2	2,095.9			209.6	314.3	1,572.0	299.2	16.9	282.3			28.3	42.3	211.6
	ADMINISTRATIVE & GENERAL																			
2.3.1	General Office	80%	20%	1,975.4	1,580.3	395.1	1,580.3	40%	60%	632.1	948.2		395.1	22.3	372.8	40%	60%	149.1	223.7	
2.3.2	Service Fees	80%	20%	1,013.0	810.4	202.6	810.4	40%	60%	324.2	486.2		202.6	11.5	191.1	40%	60%	76.5	114.7	
2.3.3	Overhead Capitalized	80%	20%	(451.6)	(361.3)	(90.3)	(361.3)	40%	60%	(144.5)	(216.8)		(90.3)	0.0	(90.3)	40%	60%	(36.1)	(54.2)	
2.3	Subtotal			2,536.8	2,029.4	507.4	2,029.4			811.8	1,217.6		507.4	33.8	473.6			189.5	284.2	0.0
	DEPRECIATION AND AMORTIZATION																			
2.4.1	Depreciation	47%	53%	5,301.1	2,508.5	2,792.6	2,508.5	40%	60%	1,003.4	1,505.1		2,792.6	138.4	2,654.2	40%	60%	1,061.7	1,592.5	0.0
2.4.2	Amortization	0%	100%	868.3		868.3		40%	60%				868.3	0.0	868.3	40%	60%	347.3	521.0	0.0
2.4	Subtotal			6,169.4	2,508.5	3,660.9	2,508.5			1,003.4	1,505.1		3,660.9	138.4	3,522.5			1,409.0	2,113.5	
	TAXES - OTHER THAN INCOME																			
2.5.1	Municipal	80%	20%	1,351.0	1,080.8	270.2	1,080.8	40%	60%	432.3	648.5		270.2	15.3	254.9	40%	60%	102.0	152.9	
2.5.2	Capital Rate Base Ratio	40%	60%	505.0	202.0	303.0	202.0	40%	60%	80.8	121.2		303.0	17.1	285.9	40%	60%	114.3	171.5	
2.5	Subtotal			1,856.0	1,282.8	573.2	1,282.8			513.1	769.7		573.2	32.4	540.8			216.3	324.4	
2.	**TOTAL EXPENSES**			25,405.3	15,987.6	9,417.6	15,987.6			3,131.2	4,696.5	8,159.9	9,417.6	239.7	9,177.9			2,457.1	3,685.3	3,035.4
3.	**REVENUE REQUIREMENT**			41,315.2	22,351.5	18,963.6	22,351.5			5,676.8	8,514.9	8,159.9	18,963.6	239.7	18,723.8			6,275.5	9,412.9	3,035.4
4.1	**GROSS REVENUE REQUIREMENT (incl. fuel)**			41,315.2	22,351.5	18,963.6	22,351.5			5,676.8	8,514.9	8,159.9	18,963.6	239.7	18,723.8			6,275.5	9,412.9	3,035.4
4.2	**GROSS REVENUE REQUIREMENT (excl. fuel)**			41,315.2	22,351.5	18,963.6	22,351.5			5,676.8	8,514.9	8,159.9	18,963.6	239.7	18,723.8			6,275.5	9,412.9	3,035.4
3.1.1	Less: UNION GAS									321.1	508.0	477.1						0.0	0.0	0.0
3.1.2	Less: CENTRA GAS									56.2	50.8	83.4						65.8	59.7	33.0
3.1.1	Less: ST. LAWRENCE									0.0	0.0	0.0						0.0	0.0	0.0
3.1	**Net: CONSUMERS GAS**									5,299.5	7,956.1	7,599.4						6,209.7	9,353.2	3,002.4

TECUMSEH GAS
RATE DERIVATION
2007 TEST YEAR

Item No.	Transmission and Compression	Col.1 Annual Demand	Col.2 Daily Demand	Col.3 Commodity
1.1	Cost of service	5,676.8	8,514.9	8,159.9
1.2	Forecasted Gas Volumes	2,863,939.2	47,515.9	5,541,951.2
1.3.1	Unit Cost - Annual ($/10³m³)	1.982	179.201	1.472
1.3.2	Unit Cost - Monthly ($/10³m³/month)	0.165	14.933	0.000
1.3.3	Unit Cost - Rounded ($/10³m³)	0.165	14.933	1.472
1.4	Fuel Ratio (%)			0.35
	Pool Storage	**Annual Demand**	**Daily Demand**	**Commodity**
2.1	Cost of Service Analysis ($000's)	6,275.5	9,412.9	3,035.4
2.2	Forecasted Gas Volumes (10³m³)	2,701,939.2	44,680.9	5,217,951.2
2.3.1	Unit Cost - Annual ($/10³m³)	2.3226	210.6695	0.5817
2.3.2	Unit Cost - Monthly ($/10³m³/month)	0.1935	17.5558	0.0000
2.3.3	Unit Cost - Rounded ($/10³m³)	0.1935	17.5558	0.5817

TECUMSEH GAS
ISOLATION OF TRANSMISSION RELATED RATE BASE
2007 TEST YEAR

($000)

				Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		FUNCTIONALIZATION TOTAL COSTS					**ELIMINATION OF COMPRESSION COSTS**		**TRANSMISSION COSTS**	
Item No.	Description	Functional Allocation T/C	Pool	Net Investment Avg. of Mnthly Avg.	Transmission & Compression	Pool Storage Space	Compression	Pool Storage Space	Transmission	Pool Storage Space
1.1	Transmission Lines	100%	0%	9,519.5	9,519.5	0.0	0.0	0.0	9,519.5	0.0
1.2	Compressor Equipment	100%	0%	54,621.6	54,621.6	0.0	(43,693.9)	0.0	10,927.7	0.0
1.3	Structures & Improvements	100%	0%	7,414.0	7,414.0	0.0	(7,414.0)	0.0	0.0	0.0
1.4	Office and Plant Equipment	100%	0%	1,250.1	1,250.1	0.0	(1,186.4)	0.0	63.7	0.0
1.5	Land	100%	0%	188.7	188.7	0.0	(188.7)	0.0	0.0	0.0
1.6.1	Allowance for - Mat'ls & Supplies	100%	0%	2,362.3	2,362.3	0.0	(2,362.3)	0.0	0.0	0.0
1.6.2	- Working Cash Allow.	100%	0%	1,100.0	1,100.0	0.0	(1,072.3)	0.0	27.7	0.0
1.7	Provision for LUF	69%	31%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.				76,456.2	76,456.2	0.0	(55,917.6)	0.0	20,538.6	0.0
2.1	Field Lines	0%	100%	19,518.3	0.0	19,518.3	0.0	(19,518.3)	0.0	0.0
2.2	Wells	0%	100%	14,275.1	0.0	14,275.1	0.0	(14,275.1)	0.0	0.0
2.3	Well Equipment	0%	100%	3,638.6	0.0	3,638.6	0.0	(3,638.6)	0.0	0.0
2.4	Measuring & Regulating	0%	100%	8,472.1	0.0	8,472.1	0.0	(8,472.1)	0.0	0.0
2.5	Gas Storage Rights	0%	100%	22,708.2	0.0	22,708.2	0.0	(22,708.2)	0.0	0.0
2.6	Petroleum and Natural Gas Leases	0%	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.7	Base Pressure Gas	0%	100%	40,767.1	0.0	40,767.1	0.0	(40,767.1)	0.0	0.0
2.8	Other	0%	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.				109,379.4	0.0	109,379.4	0.0	(109,379.4)	0.0	0.0
3.	Total			185,835.6	76,456.2	109,379.4	(55,917.6)	(109,379.4)	20,538.6	0.0

TECUMSEH GAS
ISOLATION OF TRANSMISSION RELATED COST OF SERVICE
2007 TEST YEAR

		Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9
		TOTAL COST OF SERVICE					**ELIMINATION OF COMPRESSION COSTS**		**TRANSMISSION COSTS**	
Item No.		Functional Allocation T/C	Pool	Utility Return & Expenses	Transmission & Compression	Pool Storage	Compression	Pool Storage	Transmission	Pool Storage
	RATE BASE RETURN AMOUNT			($000)	($000)	($000)				
1.1	Utility Return (net of fuel)	40%	60%	15,909.9	6,364.0	9,545.9	(4,605.6)	(9,545.9)	1,758.4	0.0
1.	Total Return	0%	0%	15,909.9	6,364.0	9,545.9	(4,605.6)	(9,545.9)	1,758.4	0.0
	EXPENSES - OPERATION									
2.1.1	Labour	80%	20%	1,428.7	1,142.9	285.7	(1,142.9)	(285.7)	0.0	0.0
2.1.2	Supplies & Other	90%	10%	355.0	319.5	35.5	(319.5)	(35.5)	0.0	0.0
2.1.3	Compressor Station Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.4	Compressor Station Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.5	Other Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.6	Other Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.3	Hydro	100%	0%	360.8	360.8	0.0	(360.8)	0.0	0.0	0.0
2.1.4	Lease Rentals	0%	100%	1,248.7	0.0	1,248.7	0.0	(1,248.7)	0.0	0.0
2.1.5	Surface Rentals	0%	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.6	Provision for LUF	69%	31%	9,054.8	6,247.8	2,807.0	(6,247.8)	(2,807.0)	0.0	0.0
2.1	Subtotal			12,447.9	8,071.0	4,376.9	(8,071.0)	(4,376.9)	0.0	0.0
	MAINTENANCE									
2.2.1	Company	90%	10%	1,798.1	1,618.3	179.8	(1,602.6)	(179.8)	15.8	0.0
2.2.2	Contractor	80%	20%	597.0	477.6	119.4	(445.6)	(119.4)	32.0	0.0
2.2	Subtotal			2,395.1	2,095.9	299.2	(2,048.2)	(299.2)	47.8	0.0
	ADMINISTRATIVE & GENERAL									
2.3.1	General Office	80%	20%	1,975.4	1,580.3	395.1	(1,556.9)	(395.1)	23.4	0.0
2.3.2	Service Fees	80%	20%	1,013.0	810.4	202.6	(808.6)	(202.6)	1.9	0.0
2.3.3	Overhead Capitalized	80%	20%	(451.6)	(361.3)	(90.3)		90.3	(49.9)	0.0
2.3	Subtotal			2,536.8	2,029.5	507.4	(2,365.5)	(507.4)	(24.7)	0.0
	DEPRECIATION AND AMORTIZATION									
2.4.1	Depreciation	47%	53%	5,301.1	2,508.5	2,792.6	(2,092.7)	(2,792.6)	415.8	0.0
2.4.2	Amortization	0%	100%	868.3	0.0	868.3	0.0	(868.3)	0.0	0.0
2.4	Subtotal			6,169.4	2,508.5	3,660.9	(2,092.7)	(3,660.9)	415.8	0.0
	TAXES - OTHER THAN INCOME									
2.5.1	Municipal	80%	20%	1,351.0	1,080.8	270.2	(780.8)	(270.2)	300.0	0.0
2.5.2	Capital	40%	60%	505.0	202.0	303.0	(146.2)	(303.0)	55.8	0.0
2.5	Subtotal			1,856.0	1,282.8	573.2	(927.0)	(573.2)	355.8	0.0
2.	**TOTAL EXPENSES**			25,405.3	15,987.7	9,417.6	(15,504.4)	(9,417.6)	794.7	0.0
3.	**REVENUE REQUIREMENT BEFORE TAXES**			41,315.2	22,351.7	18,963.5	(20,110.0)	(18,963.5)	2,553.1	0.0

FUNCTIONALIZATION OF SHORT CYCLE
NET REVENUES TO IN/EX FRANCHISE CUSTOMERS
2007 TEST YEAR
($000)

		Col. 1	Col. 2	Col. 3 (Col. 1*Col. 2)	Col. 4	Col. 5	Col. 6 (Col. 3*Col. 4)	Col. 7 (Col. 3*Col. 5)
Item No.	Description	Net Revenues ($000)	Sharing	Net Revenues Shared ($000)	T/C	Storage	T/C ($000)	Storage ($000)
1.	Short Cycle	4,368.0	100%	4,368.0	54%	46%	2,363.1	2,004.9

CLASSIFICATION AND ALLOCATION OF NET REVENUES TO IN/EX FRANCHISE CUSTOMERS

		Col. 1	Col. 2 (Col. 1*60%)	Col. 3 (Col 1*40%)	Col. 4	Col. 5	Col. 6 (Col. 4*Col. 2)	Col. 7 (Col. 5*Col. 3)	Col. 8 (Col. 6+Col. 7)
			NET REVENUES		VOLUMES		ALLOCATION		
Item No.	Description	Total ($000)	Daily ($000)	Annual ($000)	Daily	Annual	Daily ($000)	Annual ($000)	Total ($000)
	T/C								
1.1	In Franchise				100%	100%	1,417.9	945.2	2,363.1
1.2	Rate 325				0%	0%	0.0	0.0	0.0
1.3	Rate 330				0%	0%	0.0	0.0	0.0
1.4	Rate 331				0%	0%	0.0	0.0	0.0
1.	TOTAL	2,363.1	1,417.9	945.2	100%	100%	1,417.9	945.2	2,363.1
	Storage								
2.1	In Franchise				100%	100%	1,202.9	802.0	2,004.9
2.2	Rate 325				0%	0%	0.0	0.0	0.0
2.3	Rate 330				0%	0%	0.0	0.0	0.0
2.4	Rate 331				0%	0%	0.0	0.0	0.0
2.	TOTAL	2,004.9	1,202.9	802.0	100%	100%	1,202.9	802.0	2,004.9
	Total T/C and Storage								
3.1	In Franchise						2,620.8	1,747.2	4,368.0
3.2	Rate 325						0.0	0.0	0.0
3.3	Rate 330						0.0	0.0	0.0
3.4	Rate 331						0.0	0.0	0.0
3.	TOTAL	4,368.0	2,620.8	1,747.2			2,620.8	1,747.2	4,368.0

APPENDIX "C"

TO INTERIM RATE ORDER

BOARD FILE NO. EB-2006-0034

DATED MARCH 26, 2007

RIDER: E	REVENUE ADJUSTMENT RIDER

The following adjustment shall be applicable to billed volumes during the period April 1, 2007 to December 31, 2007.

Rate Class	Sales Service (¢/m³)	Transportation Service (¢/m³)
Rate 1	0.2688	0.2310
Rate 6	0.0798	0.0185
Rate 9	0.2598	0.2586
Rate 100	(0.1788)	(0.1732)
Rate 110	(0.0327)	(0.0346)
Rate 115	0.0132	0.0117
Rate 135	0.0038	0.0038
Rate 145	(0.1556)	(0.1402)
Rate 170	0.0174	0.0153
Rate 200	0.1244	0.1204
Rate 300	0.0000	(0.0640)

APPENDIX "D"

TO INTERIM RATE ORDER

BOARD FILE NO. EB-2006-0034

DATED MARCH 26, 2007

RATE HANDBOOK

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

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

Gas: Natural Gas.

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

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

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

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

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

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

Gigajoule ("GJ"): See Joule.

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

Imperial Conversion Factors:

Volume:

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

Pressure:

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

Energy:

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

Monetary Value:

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

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

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

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

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

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

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

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

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

Metric Conversion Factors:

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

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

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

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

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

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

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

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

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

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

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

T-Service: Transportation Service.

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

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

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

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

PART II

RATES AND SERVICES AVAILABLE

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

SECTION A - INTRODUCTION

1. In Franchise Services

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

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

The all-inclusive services are provided pursuant to Rates 1, 6 and 9, ("the General Service Rates") and Rates 100, 110, 115, 135, 145, and 170 ("the Large Volume Service Rates"). Individual services are available under Rates 125, 300, and 315 ("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% of all of the unpaid Enbridge Gas Distribution charges, including all applicable federal and provincial taxes, is applied to the account on the seventeenth (17^{th}) day following the date the bill is due.

SECTION G - TERM OF ARRANGEMENT

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

SECTION H - RESALE PROHIBITION

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

SECTION I - MEASUREMENT

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

SECTION J - RATES IN CONTRACTS

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

SECTION K - ADVICE RE: CURTAILMENT

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

SECTION L - DAILY DELIVERED VOLUMES

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

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

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

SECTION M - AUTHORIZED OVERRUN GAS

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

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

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

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

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

plus

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

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

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

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

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

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

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

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

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

SECTION A - NOMINATIONS

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

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

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

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

SECTION B - OBLIGATION TO DELIVER

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

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

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

SECTION C - DIVERSION RIGHTS

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

SECTION D - BANKED GAS ACCOUNT

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

SECTION E - DISPOSITION OF BANKED GAS ACCOUNT BALANCES

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

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

The Applicant, by written notice to the Company within thirty (30) days of the end of the contract year, may elect to return to the Company, in kind, during the one hundred and eighty (180) days following the end of the contract year that portion of any debit balance in the Banked Gas Account as at the end of the contract year not exceeding a volume of twenty times the Applicant's Mean Daily Volume by the Applicant delivering to the Company on days agreed upon by the Company and the Applicant a volume of gas greater than the Mean Daily Volume, if any, applicable to such day under a Service Contract. Any volume of gas returned to the Company as aforesaid shall not be credited to the Banked Gas Account in the subsequent contract year. Any debit balance in the Banked Gas Account as at the end of the contract year which is not both elected to be returned, and actually returned, to the Company as aforesaid shall be deemed to have been sold to the Applicant and the Applicant shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

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

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

(ii) Any portion of a credit balance in the Banked Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to the Company within thirty (30) days of the end of the contract year) to sell under this clause, shall be deemed to have been tendered for sale to the Company and the Company shall purchase such portion at a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the average Ontario Transportation Service Credit over the contract year. Any volume of gas deemed to have been so tendered for sale shall be deemed to have been eliminated from the credit balance of the Banked Gas Account.

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

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

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

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

RATE NUMBER: 1	RESIDENTIAL SERVICE

APPLICABILITY:

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

RATE:

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

	Billing Month
	January to December
Monthly Customer Charge	**$11.88**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**14.8804 ¢/m³**
For the next 55 m³ per month	**14.2171 ¢/m³**
For the next 85 m³ per month	**13.6973 ¢/m³**
For all over 170 m³ per month	**13.3103 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**34.1108 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

These rates to be superceded by EB-2007-0049, effective April 1, 2007.	BOARD ORDER: EB-2006-0034	REPLACING RATE EFFECTIVE: January 1, 2007	

ENBRIDGE

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	**$23.58**
Delivery Charge per cubic metre	
For the first 500 m³ per month	**13.9886 ¢/m³**
For the next 1050 m³ per month	**11.7886 ¢/m³**
For the next 4500 m³ per month	**10.2485 ¢/m³**
For the next 7000 m³ per month	**9.2586 ¢/m³**
For the next 15250 m³ per month	**8.8185 ¢/m³**
For all over 28300 m³ per month	**8.7085 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**34.2738 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

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	**$220.55**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**13.6756 ¢/m³**
For all over 20,000 m³ per month	**13.0346 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

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	**$115.10**
Delivery Charge	
Per cubic metre of Contract Demand	**8.0000 ¢/m³**
For the first 14,000 m³ per month	**4.8245 ¢/m³**
For the next 28,000 m³ per month	**3.4655 ¢/m³**
For all over 42,000 m³ per month	**2.9065 ¢/m³**
Gas Supply Load Balancing Charge	**4.3285 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9953 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

RATE NUMBER: **100**

MINIMUM BILL:

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

9.0554 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

RATE NUMBER: 110	LARGE VOLUME LOAD FACTOR SERVICE

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$554.50**
Delivery Charge	
Per cubic metre of Contract Demand	**22.1800 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5044 ¢/m³**
For all over 1,000,000 m³ per month	**0.3544 ¢/m³**
Gas Supply Load Balancing Charge	**3.8370 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

MINIMUM BILL:

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

4.2438 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

RATE NUMBER: **115**	**LARGE VOLUME LOAD FACTOR SERVICE**

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month **January to December**
Monthly Customer Charge	**$610.78**
Delivery Charge	
Per cubic metre of Contract Demand	**24.4300 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.2730 ¢/m³**
For all over 1,000,000 m³ per month	**0.1730 ¢/m³**
Gas Supply Load Balancing Charge	**3.0382 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

RATE NUMBER: **115**

MINIMUM BILL:

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

3.2136 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

EXTRA LARGE FIRM DISTRIBUTION SERVICE

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

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

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

DISTRIBUTION RATES:

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

Monthly Customer Charge	**$500.00**
Demand Charge	
Per cubic metre of the Contract Demand or the Billing Contract Demand, as applicable, per month	**8.9017 ¢/m³**
Direct Purchase Administration Charge	**$50.00**
Forecast Unaccounted For Gas Percentage	**0.3%**

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

TERMS AND CONDITIONS OF SERVICE:

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

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

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

3. **Nominations**:

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

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

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

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

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

4. **Authorized Demand Overrun:**

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

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

Authorized Demand Overrun Rate	**0.29 ¢/m³**

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

5. **Unauthorized Demand Overrun:**

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

6. **Unauthorized Supply Overrun:**

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

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

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

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

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

7. **Unauthorized Supply Underrun:**

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

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

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

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

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

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

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

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

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

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

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

Term of Contract:

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

Right to Terminate Service:

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

LOAD BALANCING PROVISIONS:

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

Definitions:

Aggregate Delivery:

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

Applicable Delivery Area:

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

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA).

Secondary Delivery Area:

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

Actual Consumption:

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

Net Available Delivery:

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

Daily Imbalance:

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

Cumulative Imbalance (also referred to as Banked Gas Account):

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

Maximum Contractual Imbalance:

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

Winter and Summer Seasons:

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

Operational Flow Order:

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

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

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

Daily Balancing Fee:

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

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

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

Tier 1 = 0.8857 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 1.0628 cents/m3 applied to Daily Imbalance of greater than 10% but less than the Maximum Contractual Imbalance

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

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

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

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

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area. Customers may also title transfer gas from their Cumulative Imbalances Account (Banked Gas Account) into a Rate 316 storage account of the customer provided that the customer has space available in the storage account to accommodate the transfer.

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

The customer's Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. In the event that the customer cannot title transfer gas from their Cumulative Imbalances Account (Banked Gas Account) in whole or in part to storage the Company shall deem the excess imbalance to be Unauthorized Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee shall be equal to 0.9999 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 or after July 1, 2007 or such earlier date as the Board may specify. This rate schedule is effective July 1, 2007 or such earlier date as the Board may specify.

RATE NUMBER: **135**	**SEASONAL FIRM SERVICE**

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m^3.

	Billing Month	
	December to March	**April to November**
Monthly Customer Charge	**$110.53**	**$110.53**
Delivery Charge		
For the first 14,000 m^3 per month	**6.6488 ¢/m^3**	**1.9488 ¢/m^3**
For the next 28,000 m^3 per month	**5.4488 ¢/m^3**	**1.2488 ¢/m^3**
For all over 42,000 m^3 per month	**5.0488 ¢/m^3**	**1.0488 ¢/m^3**
Gas Supply Load Balancing Charge	**2.5757 ¢/m^3**	**2.5757 ¢/m^3**
System Sales Gas Supply Charge per cubic metre (If applicable)	**34.0023 ¢/m^3**	**34.0023 ¢/m^3**

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

DIRECT PURCHASE ARRANGEMENTS:

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

UNAUTHORIZED OVERRUN GAS RATE:

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

Failure to deliver a volume of gas equal to the Mean Daily Volume 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.

SEASONAL CREDIT:

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

SEASONAL OVERRUN CHARGE:

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

Seasonal Overrun Charges:

December and March	**18.4490 ¢/m³**
January and February	**46.1225 ¢/m³**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**5.9936 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$117.11**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.0000 ¢/m³**
For the first 14,000 m³ per month	**2.8296 ¢/m³**
For the next 28,000 m³ per month	**1.4706 ¢/m³**
For all over 42,000 m³ per month	**0.9116 ¢/m³**
Gas Supply Load Balancing Charge	**4.0740 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**34.0363 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

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

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**6.8060 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Billing Month January to December
Monthly Customer Charge	**$268.95**
Delivery Charge	
Per cubic metre of Contract Demand	**4.0300 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5113 ¢/m³**
For all over 1,000,000 m³ per month	**0.3113 ¢/m³**
Gas Supply Load Balancing Charge	**3.4209 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

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

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **3.8346 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

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	**13.8300 ¢/m³**
Per cubic metre of gas delivered	**0.9629 ¢/m³**
Gas Supply Load Balancing Charge	**4.3007 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**33.9398 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**33.9212 ¢/m³**

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

DIRECT PURCHASE ARRANGEMENTS:

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

CURTAILMENT CREDIT:

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

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

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

UNAUTHORIZED OVERRUN GAS RATE:

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

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

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

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**5.1661 ¢/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, 2007 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

RATE NUMBER: **300**	**FIRM OR INTERRUPTIBLE DISTRIBUTION SERVICE**

APPLICABILITY:

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

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

CHARACTER OF SERVICE:

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

DISTRIBUTION RATES:

Monthly Customer Charge	**$500.00**
Monthly Contract Demand Charge Firm	**24.0202 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3512 ¢/m³**
Maximum Delivery Charge	**0.9476 ¢/m³**
Forecast Unaccounted For Gas Percentage	**0.3%**

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

TERMS AND CONDITIONS OF SERVICE:

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

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

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

3. **Nominations**:

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

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

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

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

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

4. **Authorized Demand Overrun:**

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

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

5. **Unauthorized Demand Overrun:**

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

6. **Unauthorized Supply Overrun:**

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

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

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

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

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

7. **Unauthorized Supply Underrun:**

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

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

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

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

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

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

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

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

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

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

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

Term of Contract:

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

Right to Terminate Service:

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

Load Balancing:

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

LOAD BALANCING PROVISIONS:

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

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

Definitions:

Aggregate Delivery:

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

Applicable Delivery Area:

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

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA).

Secondary Delivery Area:

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

Actual Consumption:

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

Net Available Delivery:

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

Daily Imbalance:

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

Cumulative Imbalance (also referred to as Banked Gas Account):

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

Maximum Contractual Imbalance:

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

Winter and Summer Seasons:

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

Operational Flow Order:

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

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

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

Daily Balancing Fee:

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

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

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

Tier 1 = Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance and shall be subject to a charge of 0.8857 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 1.0628 cents/m3

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

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

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

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

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area.

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

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

The Cumulative Imbalance Fee shall be equal to of 0.4362 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 or after January 1, 2007, or, on or after April 1, 2007, depending on the start date chosen by the customer. This rate schedule is effective January 1, 2007.

APPLICABILITY:

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

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

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

Storage space shall be based on the storage space algorithm [(customer's average winter demand – customer's average annual demand) x 151]. Gas fired power generation customers have the option to have storage space determined based on the methodology approved in EB-2005-0551.

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	**0.0346 ¢/m³**
Monthly Storage Deliverability/Injection Demand Charge	**12.0982 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.4999 ¢/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 or after January 1, 2007, or, on or after April 1, 2007, depending on the start date chosen by the customer.

This rate schedule is effective January 1, 2007.

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	**37.6720 ¢/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, 2007 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates as the Board Order, EB-2006-0288.

APPLICABILITY AND CHARACTER OF SERVICE:

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

RATE:

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

	Transmission & Compression $/10³m³	Pool Storage $/10³m³
Demand Charge for:		
Annual Turnover Volume	**0.1652**	**0.1935**
Maximum Daily Withdrawal Volume	**14.9334**	**17.5558**
Commodity Charge	**1.4724**	**0.5817**

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	**2.1804**	**0.4910**
Unauthorized	**-**	**197.1212**
Pool Storage		
Authorized	**2.5549**	**0.5772**
Unauthorized	**-**	**231.7365**

(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, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

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**	
	$\$/10^3m^3$	**$\$/10^3m^3$**	**$\$/10^3m^3$**
Monthly Demand Charge per unit of Annual Turnover Volume:			
Minimum	**0.3587**	**0.3587**	**-**
Maximum	**1.7936**	**1.7936**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**32.4892**	**25.9914**	**-**
Maximum	**162.4461**	**129.9569**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**2.0541**	**2.0541**	**0.8942**
Maximum	**10.2706**	**10.2706**	**38.1075**

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:	**38.1075**	**38.1075**	**38.1075**
Authorized Overrun			
Daily Injection/Withdrawal			
Negotiable, not to exceed:	**38.1075**	**38.1075**	**38.1075**
Unauthorized Overrun			
Annual Turnover Volume			
Excess Storage Balance			
September 1 - November 30	**381.0754**	**381.0754**	**381.0754**
December 1 - October 31	**38.1075**	**38.1075**	**38.1075**
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, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

APPLICABILITY:

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

CHARACTER OF SERVICE:

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

RATE:

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

	Firm $\$/10^3m^3$	Interruptible $\$/10^3m^3$
Monthly Demand Charge per unit of Maximum Contracted Daily Delivery:	**4.4780**	**-**
Commodity Charge per unit of gas delivered:	**-**	**0.1770**

MINIMUM BILL:

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

TERMS AND CONDITIONS OF SERVICE:

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

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

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

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

The Town of Collingwood
The Town of Midland

APPLICABILITY:

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

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

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

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

T-SERVICE CREDIT:

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

TOLLS CREDIT	**Type of Arrangement**	
Point of Acceptance	Firm Transportation (FT)	Firm Service Tendered (FST)
Western Canada	0.0000 ¢/m³	0.0000 ¢/m³
CDA, EDA	3.5241 ¢/m³	0.0000 ¢/m³
Dawn	3.0336 ¢/m³	0.0000 ¢/m³
Intra-Alberta	-0.4649 ¢/m³	N/A

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

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

APPLICABILITY:

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

TERMS AND CONDITIONS OF SERVICE:

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

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

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

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

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

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

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

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

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

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

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

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

    or

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

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

APPLICABILITY:

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

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

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

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

BUY / SELL PRICE:

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

FT FUEL PRICE:

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

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2007. This rate schedule is effective January 1, 2007 and replaces the identically numbered rate schedule that specifies, as the Effective Date, January 1, 2007 and that indicates, as the Board Order, EB-2006-0288.

RIDER: C	GAS COST ADJUSTMENT RIDER

The following adjustment is applicable to all gas sold or delivered during the period January 1, 2007 to December 31, 2007.

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

RIDER: E	REVENUE ADJUSTMENT RIDER

The following adjustment shall be applicable to billed volumes during the period April 1, 2007 to December 31, 2007.

Rate Class	Sales Service (¢/m³)	Transportation Service (¢/m³)
Rate 1	0.2688	0.2310
Rate 6	0.0798	0.0185
Rate 9	0.2598	0.2586
Rate 100	(0.1788)	(0.1732)
Rate 110	(0.0327)	(0.0346)
Rate 115	0.0132	0.0117
Rate 135	0.0038	0.0038
Rate 145	(0.1556)	(0.1402)
Rate 170	0.0174	0.0153
Rate 200	0.1244	0.1204
Rate 300	0.0000	(0.0640)

These rates to be superceded by EB-2007-0049, effective April 1, 2007.	BOARD ORDER: EB-2006-0034	REPLACING RATE EFFECTIVE: January 1, 2007	Page 1 of 1 Handbook 53

ENBRIDGE

RIDER: F	ATMOSPHERIC PRESSURE FACTORS

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

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

	Rate (excluding GST)
New Account Or Activation	
New Account Charge Turning on of gas, activating appliances, obtaining billing data and establishing an opening meter reading for new customers in premises where gas has been previously supplied	$25.00
Appliance Activation Charge - Commercial Customers Only Commercial customers are charged an appliance activation charge on unlock and red unlock orders, except on the very first unlock and service unlock at a premise.	$65.00 minimum 1/2 hour work. Total Amount depends on time required
Meter Unlock Charge - Seasonal or Pool Heater Seasonal for all other revenue classes, or Pool Heater for residential only	$65.00
Statement of Account	
Lawyer Letter Handling Charge Provide the customer's lawyer with gas bill information.	$15.00
Statement of Account Charge (for one year history)	$10.00
Cheques Returned Non-Negotiable Charge	$20.00
Gas Termination	
Red Lock Charge Locking meter or shutting off service by closing the street shut-off valve (when work can be performed by Field Collector)	$65.00
Removal of Meter Removing meter by Construction & Maintenance crew	$260.00
Cut Off At Main Charge Cutting service off at main by Construction & Maintenance Crew	$1,200.00
Valve Lock Charge Shutting off service by closing the street	
shut-off valve - work performed by Field Investigator	$125.00
- work performed by Construction & Maintenance	$260.00

Safety Inspection

Inspection Not Ready Charge (safety inspection) When a builder requests an unlock and the appliance(s) are not ready for inspection, this charge will apply to cover the cost of returning to the same property for the additional inspection.	$65.00
Inspection Reject Charge (safety inspection) Energy Board Inspection rejects are billed to the meter installer or homeowner.	$65.00

Meter Test

Meter Test Charge When a customer disputes the reading on his/her meter, he/she may request to have the meter tested. This charge will apply if the test result confirms the meter is recording consumption correctly.	
Residential meters	$97.50
Non-Residential meters	Time & Material per Contractor

Street Service Alteration

Street Service Alteration Charge For installation of service line beyond allowable guidelines (for new residential services only)	$32.00

NGV Rental

NGV Rental Cylinder (weighted average)	$12.00

Other Customer Services (ad-hoc request)

Labour Hourly Charge-Out Rate	$130.00
Cut Off At Main Charge - Commercial & Special Requests Cut Off At Main charges for commercial services and other residential services that involve significantly more work than the average will be custom quoted.	custom quoted
Cut Off At Main Charge - Other Customer Requests Other residential Cut Off At Main requests due to demolitions, fires, inactive services, etc. will be charged at the standard COAM rate.	$1,200.00
Meter In-Out (Residential Only)) Relocate the meter from inside to outside per customer request	$260.00
Request For Service Call Information Provide written information of the result of a service call as requested by home owners.	$30.00
Temporary Meter Removal As requested by customers.	$260.00
Damage Meter Charge	$360.00

APPLICABILITY:

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

ENHANCED TITLE TRANSFER SERVICE:

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

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

Administration Charge:

Base Charge	$50.00	per transaction
Commodity Charge	$1.3115	per 10^3m^3

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

GAS IN STORAGE TITLE TRANSFER:

An Applicant that holds a contract for storage services under Rate 315 or 316 may elect to initiate a transfer of title to the natural gas currently held in storage between the storage service and another storage service held by the Applicant, or a 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