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Report for

Enbridge Gas Distribution

Analytical Review of the September 2011 PEG-R Report

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1 Executive Summary

On February 25, 2011, the Ontario Energy Board (Board) announced that it would conduct a preliminary assessment of the incentive regulation (IR) plans of two natural gas utilities: Enbridge Gas Distribution Inc. (EGD) and Union Gas Ltd. (Union). The scope of the Board's assessment was to examine the salient historical trends of the two utilities, prior to and during the incentive regulation period. As part of this assessment, the two utilities were compared to each other and to similar utilities. The comparisons involved areas such as economic performance, cost to consumers, shareholder value, capital investment, productivity, and efficiency. The goal of the assessment was to determine what impact the IR plans had in these areas.

1.1 The Pacific Economics Group Research Report

Pacific Economics Group Research, LLC (PEG-R) was retained by the Board to provide expert advice in the preliminary IR assessment. In September of 2011, the Board released a report authored by PEG-R entitled *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans* (PEG-R Report).

Power System Engineering, Inc. (PSE) was engaged by EGD to prepare the present report (PSE Review), which provides a preliminary review and appraisal of the key PEG-R Report findings, primarily as they pertain to EGD. The preliminary nature of the PSE Review's analysis is largely due to our current inability to review PEG-R's working papers, calculations, and clarify results as of yet. The Board has stated that the PEG-R Report will be filed in EGD's cost of service proceedings, and this will then provide an opportunity for a more complete analysis and evaluation of the PEG-R Report.

The PSE Review is not meant to investigate or make a judgment on the actual productivity trends of EGD or the industry. Rather, this PSE Review is meant to review the PEG-R Report's findings and provide improvements to PEG-R's methodology. PSE's improvements present the Board and other stakeholders with a more accurate depiction of EGD's performance during IR.

In the PSE Review, we will assume PEG-R performed its statistical calculations correctly and accurately, but we cannot yet independently verify the calculations. At the time of the discovery process, we will be able to evaluate the accuracy of the calculations made by PEG-R. Although we assume PEG-R's mechanical calculations are correct, we ultimately disagree with some of its assumptions and methodology.

In particular, we conclude that PEG-R's "backcasting" method of determining EGD's expected productivity trend during the IR period is incomplete. This results in PEG-R's mistaken conclusion that EGD has a fair amount of room to improve its total factor productivity. A more complete analysis, as presented in this PSE Review, shows convincing evidence that this is not the case.

1.2 Points of Agreement with the PEG-R Report

Our preliminary analysis of the PEG-R Report indicates that it includes a number of findings that PSE supports in its assessment of incentive regulation and EGD's performance within that framework. Our main objection to the PEG-R Report is discussed in Section 1.3 of this PSE Review.

The findings which PSE supports contained within the PEG-R Report include:

- EGD's positive response to incentive regulation, as demonstrated by its effective cost controls and higher productivity and efficiency;
- EGD's declining rates during the IR period, which have benefited customers; and
- EGD's ability to achieve strong cost containment despite rapidly growing input prices, particularly relative to the Canadian GDP-IPI during the examined incentive regulation period.[1]

These findings by PEG-R show that EGD has responded to IR in a manner that has benefitted its customers. Higher productivity and efficiency ultimately lead to lower gas delivery rates. The economic benefit of lower rates goes without saying. However, this is a very atypical outcome for most gas distributors in North America. As PEG-R correctly points out, the gains in efficiency, productivity, and the decline in prices occurred during a time when EGD faced input prices that were growing faster than the Canadian GDP-IPI.

Therefore, we believe much of the PEG-R Report to be accurate. However, our analysis indicates that PEG-R's methodology of estimating EGD's "expected" total factor productivity significantly inflates PEG-R's estimate of this value. We summarize the flaws in the PEG-R methodology in the following section.

1.3 Deficiency in the PEG-R Report: TFP Trend Methodology

PSE substantially agrees with PEG-R on the bullet points listed in the previous section. However, PEG-R states one conclusion with which we must disagree: the conclusion that EGD has room to improve its productivity beyond its current level. Our analysis shows that PEG-R's assessment of EGD's expected TFP trend is incorrectly inflated, due to their selected methodology.

PEG-R makes the conclusion that EGD has room to improve its TFP by comparing EGD's measured TFP trend of 0.93% (during the examined incentive regulation period of 2008-2010) to PEG-R's calculated TFP "backcast" of 1.25% during that same period. PSE's Review will demonstrate that the PEG-R method used to determine the TFP prediction of 1.25% can be improved to provide a more accurate and appropriate depiction of EGD's expected TFP.

[1] PEG-R's conclusions are summarized in Section 1.2 of the PEG-R Report ("Summary of Results," pp. 3-12).

A "backcast" is defined by PEG-R as follows:

> A "backcast" is analogous to a forecast except it generates counterfactual scenarios for the past rather than hypothetical scenarios for the future. In this instance, our objective was to predict what the TFP growth of a typical North American gas distributor would have been if it had operated under the business conditions of EGD and Union, respectively, in the 2005 – 2010 period. We define a typical gas distributor as one that operates with average efficiency.[2]

Thus, a backcast as so defined is similar to a benchmarking study: PEG-R is comparing EGD's measured TFP growth to that of a "typical" gas distributor with "average efficiency." PEG-R calculates EGD's TFP trend for 2008-2010 to be 0.93%, and then compares this measured trend to the expected (backcast) trend, which they find to be 1.25%.[3]

Based on these results, PEG-R claims that EGD has room to increase its TFP trend, and that a typical gas distributor facing EGD's circumstances would have had TFP growth that is 0.32% higher than EGD achieved during that period. This PSE Review shows that PEG-R's claim is mistaken, because it uses an incomplete and mis-specified TFP backcast methodology.

1.4 Improving PEG-R's Methodology

In this PSE Review, we recommend three improvements to the PEG-R TFP backcast methodology. We also provide preliminary estimates of the impact of these improvements on the expected TFP of EGD during the examined IR timeframe. The improvements appear to lower EGD's expected TFP trend during 2008-2010 by over 300 basis points. We find that a more accurate and appropriate approach indicates that EGD's expected TFP during the IR period is not 1.25% per year, as PEG-R claimed, but rather -1.80% per year.

The three suggested improvements on the expected TFP trend are:

1. <u>Revert to PEG-R's 2007 methodology for econometric TFP backcasts</u>. The 2011 PEG-R Report altered PEG-R's prior methodology to include the expected productivity impacts of business condition variables. PEG-R presented evidence in their 2007 report that this method will distort expected TFP measures; however, they decided to include these impacts in their current methodology. PSE conducted further research that substantiates PEG-R's 2007 finding that the inclusion of long-run business condition variable impacts on short-run TFP projections is not warranted and leads to distorted results. We suggest reverting to PEG-R's original methodology of not including business condition impacts in the calculation of expected TFP trends.

[2] PEG-R Report, Section 6.2.1.1 (p. 94).

[3] PSE is not endorsing the measured TFP growth of 0.93% for EGD. However, we are assuming in the PSE Review that PEG-R calculated this accurately. During the discovery process, we will be able to make more robust statements regarding this number. One obvious item that should be further explored is that PEG-R appears to exclude gas delivery volumes in their construction of TFP trends. Typical productivity research includes volumes as an output in the measurement of TFP trends. The rationale for PEG-R departing from this standard practice should be explored further.

2. Estimate the time trend variable using a more applicable time period. PEG-R is estimating the expected 2005-2010 TFP performance of EGD using model results that are derived from a dataset that begins in 1999 and ends in 2009. While PSE recognizes the requirement to have sufficient observations in the estimation of an econometric cost model, we put forth a model that is very similar to the PEG-R model but based on 2002-2009 data. This provides a more applicable time period in which to evaluate the performance of EGD during 2005-2010.

3. Beginning level cost efficiency should be accounted for when calculating expected TFP trends. Concentric's January 2012 *Benchmarking Study* provides strong evidence of EGD's top quartile O&M cost efficiency relative to its industry peers. PSE found statistically significant evidence within the U.S. natural gas distribution industry that the beginning period O&M cost efficiency influences future short-run TFP trends. Formulating an expectation of TFP trends is incomplete without incorporating the beginning level cost efficiency of the examined company.

1.5 Examining the Upward Bias Inherent in the PEG-R Methodology and Comparison to PSE Suggested Improvements

PSE attempted to replicate the TFP trends for the PEG-R industry sample, to compare EGD's TFP (as measured by PEG-R) to the industry as a whole. Without access to the actual data values and exact methods used by PEG-R, this replication is only approximate. The replication process can be finalized, if desired, after the discovery process is completed. Our preliminary findings are that in recent years, the industry average and median TFP trends have been negative. PSE's preliminary assessment is that, on average, the measured industry TFP (using the PEG-R U.S. sampled utilities and calculation methods) *declined* by about 0.77% per year from 2007-2009. The industry median decline was 1.43%. Figure 1-1 compares these negative U.S. industry trends to EGD's measured performance of positive TFP growth of 0.93%.

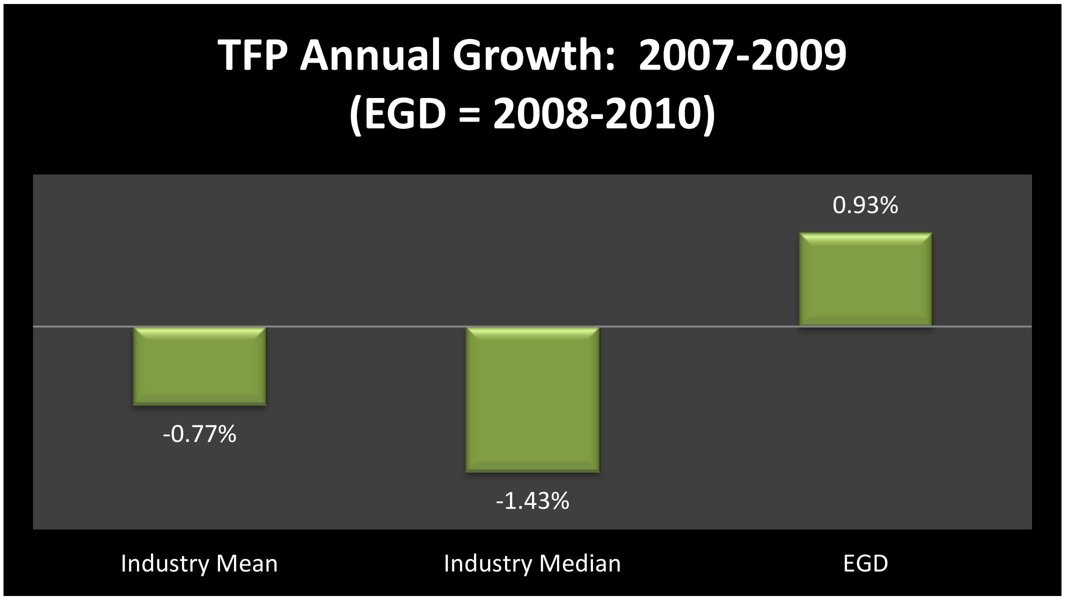


Figure 1-1 Measured TFP Growth: Industry Mean/Median vs. EGD

Figure 1-1 shows the annual TFP growth for the industry mean, the industry median, and EGD over a three-year period.[4] We should reiterate that the PEG-R method used to measure EGD's TFP growth of 0.93% (and the industry TFPs) is not disputed here, at least in our preliminary review. What we dispute is PEG-R's method for calculating the "backcasted" (or "expected") TFP.

We illustrate the bias inherent within the PEG-R backcast methodology in Figure 1-2. That figure provides an estimate of the *measured* TFP trends of the PEG-R United States sample, and compares it to what the industry's *estimated* trend would be using PEG-R's backcast methodology. The figure also presents PSE's calculation of the industry trend using our improved methodology.

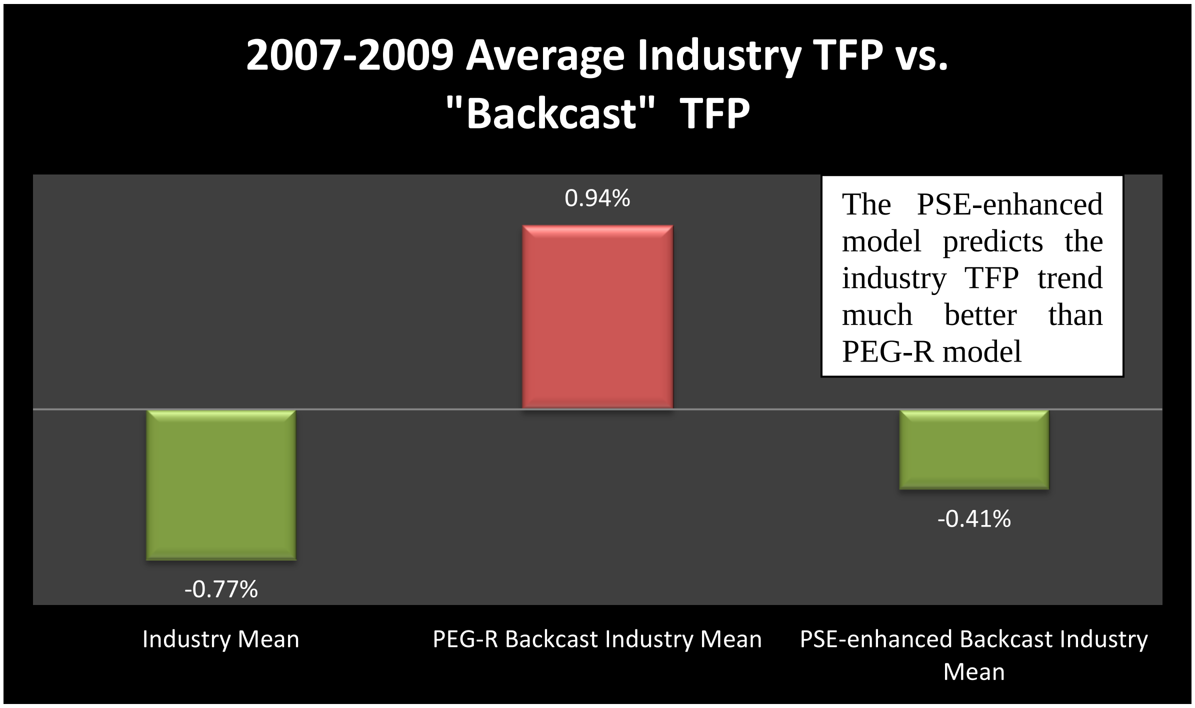
As mentioned above, the measured average industry TFP *declined* by about 0.77% per year from 2007-2009. However, the PEG-R backcast methodology indicates the industry "should" have had an average TFP *growth* of 0.94% per year. This large mismatch between PEG-R's backcasted TFP trends and the measured TFP trends provides strong evidence for an upward bias in PEG-R's current TFP backcast methodology.

Examining how well a model predicts sample outcomes is key to determining its accuracy and validity. In this report we provide evidence that the PEG-R methodology gives TFP predictions which are demonstrably too large. However, PSE's enhancements to the model increase its

[4] In the PEG-R Report, it appears that the authors are calculating growth rates for the 2008-2010 time period using the average growth rate beginning in year 2007. They are averaging the growth from 2007 to 2008, 2008 to 2009, and then 2009 to 2010, and classifying this as the 2008-2010 average annual growth rate. While PEG-R's label of "2008-2010" is somewhat unorthodox (it would typically be called a 2007-2010 growth rate), PSE uses this same labeling convention in this document to remain consistent with the PEG-R Report and minimize confusion. For the industry numbers, the time period of 2007-2009 is used, because as of the time of this PSE Review, the 2010 industry numbers are not yet available.

accuracy. In other words, the PSE-enhanced model predicts the actual observations much more accurately than the PEG-R model. This is illustrated in Figure 1-2 below.

Figure 1-2 Industry Mean TFP: Measured vs. PEG-R Backcasted vs. PSE Backcasted



Similar increases in accuracy are achieved when the PSE enhancements are applied to EGD. PEG-R estimated that EGD's backcast trend was 1.25% per year. Our initial assessment, using PEG-R's backcast framework combined with PSE's enhancements, indicates that a more appropriate expected TFP growth trend for EGD during 2008-2010 would be around -1.80% per year.

1.6 Implications for the X-Factor

EGD's annual TFP growth of 0.93% per year (as measured by PEG-R) is substantially above the -1.80% expected mark (as measured with PSE's improvements)—2.73% per year above. PEG-R's conclusion that EGD has scope to increase this trend in the future does not appear to be accurate. In fact, given the strong productivity results of the company in recent years relative to industry expectations, it is likely that the opposite is true: we would expect EGD's TFP to fall back closer to the "expected" value in upcoming years.

Table 1-1 EGD's Measured vs. Expected TFP

IR Measured TFP Growth	Expected Backcast TFP (using PSE improvements)	Difference
0.93%	-1.80%	**2.73%**

PSE used the revised expected TFP trend and other information to provide a historical examination of the X-Factor during the 2008-2010 period.[5] This "Backcast" X-Factor is -2.00% (as calculated by using the PSE-improved backcast TFP method). We then compared this to the "actual" X-factor for EGD as realized in its IR plan (0.72%, as measured by PEG-R). Our preliminary findings are that EGD's measured X-Factor was over 250 basis points greater than the expected X-Factor, given all historical factors such as expected TFP, observed output growth, and observed input price inflation. Table 1-1 summarizes the difference.

Table 1-2 EGD's Measured vs. Expected X-Factor

IR Measured X-Factor	Expected Backcast X-Factor (using PSE improvements)	Difference
0.72%	-2.00%	**2.72%**

1.7 Conclusion

PSE is supportive of the Board's initiative to examine each gas utility's performance under IR. This is a helpful exercise to assure that utilities are offering strong value to stakeholders. We also agree with PEG-R's approach of emphasizing the productivity trends of the gas utilities and comparing them to industry standards. This approach is informative, because ultimately productivity trends will influence utility cost levels and revenue requirements. Thus the PEG-R focus on the TFP trends is the correct general approach. This PSE Review has provided specific improvements that make the general approach more accurate.

Our preliminary research in this PSE Review indicates that EGD's productivity trend was well above that of the industry and therefore provided strong value to stakeholders. This high productivity trend has provided consumers with lower rates than would have normally been the case.

[5] Under incentive regulation, the allowed rate of change in the price of natural gas is generally restricted by the growth in an inflation factor minus a productivity offset and a stretch factor. The productivity offset is often called an "X-Factor," and can include other offsets, such as an industry input price differential. See Section 5 of this Review for more details.

2 Introduction to the PEG-R Methodology

On February 25, 2011, the Board announced that it would conduct a preliminary assessment of the incentive regulation plans of EGD and Union. The scope of this assessment was to examine the salient historical trends of the two natural gas utilities both prior to and during the incentive regulation period. As part of this effort, utility results were compared to each other and to similar utilities. PEG-R was retained by the Board to provide expert advice in the preliminary incentive regulation assessment. In September 2011, the Board released PEG-R's Report.

2.1 PEG-R's Backcast Model

As stated in the Executive Summary, this PSE Review provides a preliminary review and appraisal of the key PEG-R Report findings, primarily as they pertain to EGD. In particular, we will analyze and suggest enhancements to PEG-R's benchmark (backcast) TFP trends. However, in making these suggested research enhancements to PEG-R's modeling approach; PSE is not implicitly approving that paradigm.[6]

For example, PEG-R employs an econometric model to develop TFP "backcasts," which are similar to benchmarks. Backcasts estimate what the TFP "should" have been for a previous time period, given the relevant factors. PEG-R uses this econometrically-derived TFP prediction as an estimate of EGD's "expected" past TFP, and compares it to EGD's measured past TFP trend. PSE has a number of suggested enhancements to improve PEG-R's calculation of the TFP backcast, but we are not convinced the econometric backcast method is the best way to calculate expected annual TFP growth.

On the contrary, we do not see the necessity of deviating from the more conventional approach of using an industry-wide TFP trend as the basis for determining the proper future TFP trend for EGD. (Alternatively, a suitably large peer group could be used as the basis.) This is especially true during the examined incentive regulation time period of 2008-2010, when EGD's customer growth has moved much closer to U.S. industry standards.[7]

In fact, in Section 3.4, PSE provides strong evidence for the merits of using large peer group TFP trends versus PEG-R's TFP backcast methodology. This evidence shows the potential bias in PEG-R's research by comparing the average TFP trends of their sample (as measured) with the average TFP backcast (predicted) trends of their sample. This analysis showed that PEG-R's methodology expected, on average, TFP growth of 0.94% per year, whereas the average sample

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[6] Here we note another feature of PEG-R's approach to calculating TFP trends. The PEG-R authors derive an output index using cost elasticity weights, and customers and pipeline length as the relevant industry outputs. In other research on TFP trends throughout the industry, revenue weights serve as the basis for creating an output index, and these typically have the number of customers and gas delivery throughput as their outputs. A customer growth adjustment is necessary when using revenue-weighted TFP trends to calculate an X-factor in EGD's revenue per customer incentive regulation formula.

[7] As stated above, in the PEG-R Report it appears that the authors are calculating growth rates for the 2008-2010 time period using the average growth rate beginning in year 2007. They are averaging the growth from 2007 to 2008, 2008 to 2009, and then 2009 to 2010 and classifying this as the 2008-2010 average annual growth rate. While this label is somewhat unorthodox (this would typically be called a 2007-2010 growth rate), PSE uses this same labeling convention in this document to remain consistent with the PEG-R Report and minimize confusion.

measured TFP trend *declined* by 0.77% per year from 2007 to 2009. This amounts to an upward bias in their methodology of 1.71%.

2.2 PEG-R's Conclusions Regarding EGD's Response to IR

PEG-R showed that both EGD and Union have responded positively to incentive regulation. PEG-R states on page 121 of its report that:

> [PEG-R's] analysis indicates that the IR plans encouraged both EGD and Union to control costs more effectively and generate productivity and efficiency improvements.

The evidence used by PEG-R to substantiate this claim is based on an examination of each utility's TFP trend and a comparison of this trend to what PEG-R calls a "TFP backcast," based on the performance and trends of the U.S. gas utility industry as a whole (or of a group of utilities identified by PEG-R as a peer group).

The positive responses by EGD and Union provided tangible benefits to Ontario's gas customers. PEG-R notes that EGD's gas rates (as paid by its customers) declined over the examined incentive regulation period of 2008-2010. This is noteworthy, because even while EGD's input prices and prices in general were trending upward, the gas delivery prices charged were declining for EGD's customers.

PEG-R shows in Table 9 of its report that the input prices facing EGD during the 2008-2010 period increased by an annual rate of 2.11%. The Canadian GDP-IPI increased by 1.66% during this same time period. According to PEG-R, EGD's input prices rose about 0.45% faster than prices for the economy at large, while EGD's gas delivery rates still fell by 0.32%. On page 73 of its report, PEG-R states that "… input price inflation for EGD and Union outstripped the growth in both the GDP-IPI inflation factor and the Companies' gas delivery prices."

PEG-R correctly points out on page 63 that this input price differential of 0.45% between EGD's input price inflation and the increase in the GDP-IPI, which was used in the formulation of the incentive regulation plan, implies that customers received a "windfall gain at the expense of shareholders." Proper incentive regulation mechanics would suggest that this "inflation differential" be added to the GDP-IPI growth rate (or be subtracted from the X-factor) to allow the inflation factor to more accurately track the input price trends faced by EGD. In Section 5 of the PSE Review, we take the step of examining the X-Factor in light of this information.

2.3 The PSE Review

PEG-R notes that the differential between the EGD observed TFP trend and the predicted trend narrowed during the IR period. They also make the claim that "our analysis implies that there is scope for EGD to boost its TFP." Sections 3 and 4 of this Review evaluate the PEG-R statement that EGD's TFP growth was below the expected level.[8]

[8] Again, our evaluation will necessarily be more qualitative in nature and not make definitive conclusions on the effects of a given methodological alternative, due to our current inability to fully examine PEG-R's research.

Our preliminary analysis finds that EGD substantially outperformed its expected TFP trend during the examined IR period. This refutes PEG-R's conclusion that EGD has scope to increase its TFP trend beyond the observed 0.93%. In other words, PEG-R concluded that EGD underperformed its expected TFP trend in recent years and so has room to improve. In fact, the opposite is likely to be true. Given the rapid TFP growth of EGD in recent years relative to industry standards, we would expect EGD to move closer to industry norms in future years.

In Section 5 of this Review, PSE calculates what an appropriate X-Factor would have been during 2007-2010 given the now available historical growth rates of output and input prices, combined with our enhanced assessment of expected TFP growth. This X-Factor equals -2.00%. This is relative to the measured implicit X-Factor that EGD faced during this timeframe of 0.72% (as calculated by PEG-R on page 46 of their report).

3 Analysis of PEG-R's TFP "Backcasts"

PEG-R uses econometrically informed backcasts to compare EGD's measured TFP growth with PEG-R's "expected" TFP growth. Table 23 of the PEG-R Report presents results of the comparison. The expected TFP growth is based on an econometrically estimated total cost function.

The econometric sample included 34 U.S. gas distribution utilities over a sample period of 1999-2009. On the basis of these results, PEG-R states that EGD's TFP performance improved during the incentive regulation period. However, they also make the claim that there is room for improving this trend, based on the assumption that the backcast TFP growth was higher than EGD's measured growth. (This Review shows PEG-R's projected backcast TFP growth to be mistaken.) A summary of PEG-R's Table 23 as it pertains to EGD is provided in Table 3-1 below.

Table 3-1 EGD's Measured vs. Expected TFP (PEG-R Report)

Time Period	Expected TFP Growth	Measured TFP Growth	Difference	Conclusion Based on Results in Table
2005-2007	1.92%	1.29%	-0.63%	EGD has room to improve
2008-2010	1.25%	0.93%	-0.32%	EGD has room to improve

The expected TFP growth uses the econometric estimates found in Table 20 of the PEG-R Report. These estimates are then used to predict the average annual cost growth of EGD over the 2005-2007 and 2008-2010 time periods, given EGD's change in their outputs and business conditions over those same time periods. The cost growth estimates are found in Table 21. Table 22 of the PEG-R Report then takes the predicted cost growth estimates and translates them into predicted TFP trends by subtracting the input price index from the estimated cost growth, and adding in the change in the output quantity index.

This method of projecting TFP, while appearing to be mathematically accurate, is more cumbersome and more difficult to evaluate then the more straightforward TFP decomposition method presented by Pacific Economics Group in its November 2007 report, *Rate Adjustment Indexes for Ontario's Natural Gas Utilities*.[9] The "2007 method" was also published by PEG-R personnel in a 2009 article in the academic journal of *Review of Network Economics.*[10]

[9] The authors of the November 2007 report included the president of PEG-R, Mark Lowry, and a co-author of the PEG-R Report, Dave Hovde. The other two authors of the November 2007 report, Steve Fenrick and Lullit Getachew, now are employed by PSE and are the authors of this review.

[10] Lowry, Mark N. and Lullit Getachew (2009). "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry," *Review of Network Economics*. Volume 8, Issue 4 – December 2009. The two co-

Given PSE's current inability to obtain comments on a number of questions we have on the new calculations in the PEG-R Report, we decided to use PEG-R's 2007 method of projecting TFP trends when evaluating predicted TFP trend for EGD. This provides consistency of calculations and resolves a number of our questions on their new approach. The established TFP decomposition method yields very similar results to PEG-R's new method.

In the following three sections (3.1, 3.2, 3.3), we use the 2007 method to derive expected TFP trends for EGD for the 2008-2010 period. We then present the estimated impacts of three suggested enhancements on the expected EGD TFP trend for 2008-2010. Since the 2007 method and PEG-R's method as stated in the PEG-R Report appear to provide similar results, these three enhancements and their impact on expected TFP trend estimates are applicable to both methods of calculating expected TFP trends. In this Review, PSE uses the previously designed 2007 method to calculate expected TFP, due to our inability to request further information from PEG-R on its new method, and due to the fact that the new method is less straightforward than the 2007 method.

We now turn to the three enhancements that would improve the PEG-R methodology, thus producing a more accurate TFP expectation for EGD.

3.1 Enhancement #1: Eliminate Long-Run Impacts of Business Condition Variables in Short-Run Research

Table 3-2 below presents the TFP decomposition method presented in the November 2007 report, updated to reflect the new results and econometric model found in the PEG-R Report. The 2007 report did not include in its TFP calculation the influence of what PEG-R calls "business condition variables." PEG-R found two such variables to be potentially relevant: the percentage of mains that are non-cast iron and bare steel, and the number of electric customers.[11] However, PEG-R did not include business condition variables in the 2007 report's calculation of expected TFP trends, as those variables tend to influence TFP trends over the long term rather than the short term.

In the PEG-R Report of 2011, however, when evaluating EGD's 2008-2010 expected TFP, PEG-R has deviated from its prior practice, and included the long-term influence of business condition variables, despite the fact that an extremely short-term trend (TFP) is being evaluated. The inclusion of business condition variables in the 2011 PEG-R Report skews the benchmark TFP trend of EGD (and for the entire sample, as we will show in Section 3.4), and is counter to past statements made by PEG-R on this same topic.

In the 2007 report, PEG-R conducted research on the validity of including business variables into TFP projections. In that report, PEG-R states on page 49 that:

> The econometric models also provide us with an estimate of the effect of cast iron

authors of this article are the current president of PEG-R, Mark Lowry, and the co-author of this PSE Review, Lullit Getachew.

[11] The "electric customers" variable is obviously not relevant here.

> replacement on TFP growth. This could potentially be added to the econometric TFP trend target for Enbridge since it has been reducing the amount of cast iron on its system in recent years and expects to accelerate the replacement during the IR plan term. As discussed in Section 3.3.2, we found that cast iron mains raise total cost. This finding implies that a reduction in cast iron accelerates TFP growth in the long run. **However, the short and medium term effect on TFP growth may be different since the O&M cost savings may be offset initially by the cost impact of the installation of new pipe.** As an extra check, we therefore regressed the growth in the TFP of our sampled U.S. utilities on the change in their cast iron reliance using data for the sample period. **Using each approach to TFP capital costing, the estimated effect of reduced cast iron reliance was found to be statistically insignificant**. (Bold emphasis added.)

PSE conducted analysis similar to the PEG-R 2007 analysis, and we found similar results. The PSE analysis can be found in Section 3.3. In the analysis in Section 3.3, the percentage change in cast iron and bare steel is <u>not</u> a statistically significant driver of TFP trends. In fact, while our calculated result was not statistically significant, the coefficient estimate was negative, not positive. A negative coefficient here would mean that as utilities incur the costs of replacing cast iron and bare steel mains, their short-run TFP trends tend to *decline*.

This analysis, combined with PEG-R's 2007 analysis and their previously stated position provides a strong rationale for not including business condition variables in the TFP projections. If these variables are included, as in the 2011 PEG-R Report, it will lead to an upward bias in the expected TFP trends of EGD and the entire U.S. sample. This upward bias is demonstrated in Section 3.4.

Table 3-2 displays TFP projections without business condition variables (using the PEG-R 2007 methodology).

Table 3-2 TFP Projections Using 2007 Method

TFP Growth Projections from Econometric Research for EGD

Sample Years	2005-2007	2008-2010
Elasticity Estimates from PEG-R cost model		
Customers [A]	0.716	0.716
Line Miles [B]	0.167	0.167
Sum of Output Elasticities [C = A + B]	0.883	0.883
Output Index Weights from PEG-R cost model		
Customers [D = A/C]	0.811	0.811
Line Miles [E = B/C]	0.189	0.189
Subindex Growth based on PEG-R Report		
Customer [F]	2.84%	1.83%
Line Miles [G]	0.52%	0.49%
Output Growth (elasticity weighted)		
[H = D*F + E*G]	2.40%	1.58%
Returns to Scale [I = (1-C)*H	0.28%	0.18%
Technology Change [J]	0.63%	0.63%
TFP Projection "2007 Method" [K = J+I]	**0.91%**	**0.81%**

As is evident from Table 3-2, the TFP projections using the 2007 method are lower than PEG-R's 2011 "backcast" calculations for EGD over both examined time periods. (Recall that the PEG-R Report gave a backcasted value of 1.25% per year over 2008-2010.) EGD's measured TFP growth during the incentive regulation time period is (using the 2007 method predictions) more rapid than the TFP projection.

As PEG-R stated in the 2007 report, there is currently no statistical evidence to include the conversion from cast iron pipes into TFP growth. While the econometric model identifies this as a *long run* cost driver, this certainly does not necessitate that there will be a *short run* TFP influence. In fact, the evidence presented by PEG-R in 2007 and our update of that evidence appears to strongly contradict the inclusion of business condition variables.

Table 3-3 updates Table 3-1 using the results based on PEG-R's previous methodology. With this simple correction we note that EGD's TFP growth has outpaced the predicted level by 0.38% and 0.12% in the 3 years preceding IR and the 3 years during IR, respectively.

Table 3-3 EGD's Measured and Expected TFP using 2007 Method

Time Period	Expected TFP Growth	Measured TFP Growth	Difference	Conclusion Based on Results in Table
2005-2007	0.91%	1.29%	0.38%	EGD outperformed industry
2008-2010	0.81%	0.93%	0.12%	EGD outperformed industry

3.2 Enhancement #2: Use a Dataset with a More Applicable Time Period

PSE believes that Table 3-3 still does not accurately depict the TFP performance of EGD during the examined time period. This is because PEG-R developed the TFP projections using a dataset that included U.S. industry observations from 1999-2009 in order to develop predictions for the examined 2008-2010 incentive regulation time period. This mismatch in time periods significantly influences the predicted TFP value, primarily due to a higher time trend estimate.[12,13] Section 3.4 provides strong evidence on the impact and resultant bias of this mismatch.

In comparing the time trend estimate in the November 2007 report to the current one in the PEG-R Report, we notice a significant downward trend. In 2007, PEG-R used a dataset consisting of data from 1994-2004. By rolling the time period forward five years to 1999-2009, we see the time trend was almost halved. In the 2007 PEG-R report the 1994-2004 time trend was 1.19%, but now it is 0.63% (as calculated in the 2011 PEG-R Report, using the 1999-2009 time period).[14]

[12] A "time trend estimate" is a variable that: (1) reflects the trend of an average utility's total costs after adjustments for all other included variables (e.g. input price inflation) and (2) captures the trend in cost from other possible covariates that are not in the model.

[13] Given what appears to be PEG's definition of 2008-2010, whereby they are actually averaging the growth rates of 2007 to 2008, 2008 to 2009, and then 2009 to 2010, the dataset should include data from 2007 to 2010 in order to provide an "apples to apples" comparison to the estimated 2008-2010 TFP trend of EGD.

[14] This was using the "cost of service capital" costing method for both reports. In 2007, PEG-R reported econometric models for two methods of capital costing: cost of service and geometric decay. In the current report they only show results based on the cost of service method.

We see a significant slowdown in the technological change of the industry in recent years. This is also revealed in measured TFP trends that are declining in recent years. It seems very likely that if PEG-R had used a shorter and more comparable time period in its dataset, the time trend would have been further reduced.

PSE recognizes the requirement for a dataset containing a large enough number of observations to accurately estimate coefficient estimates. For example, a dataset containing only 2007-2009 data would only have 102 observations (3 years multiplied by 34 utilities) given PEG-R's sample of 34 utilities. Given the complexity and number of variables contained in their estimated translog cost function, there are likely not enough statistical degrees of freedom to limit the dataset to this short of a timeframe. However, given the industry TFP slowdown in recent years, the dataset should be limited to the most recent time frame available while still maintaining the integrity of the econometric model.

We attempted to shorten the dataset time span so that it more accurately reflects the time period that EGD is being compared against. This will provide a more applicable time trend estimate versus the dataset used by PEG-R. The PSE estimated time trend will be more reflective of the conditions faced by gas distributors during the 2005-2010 evaluation period. PEG-R's dataset includes the unnecessary influence of observations that occur in the late 1990's and early 2000's. Keep in mind, this is a preliminary analysis based on our "best guess" of PEG-R's data and econometric methods used.

The first econometric model that we estimated used the exact same specification as PEG-R (as far as we can tell) but limited the sample to 2002-2009. As expected, the time trend variable decreased to 0.13% in contrast to the PEG-R estimate of -0.63%. This finding was not statistically significant,[15] thus the null hypothesis of a trend value of 0.00% cannot be rejected. In this model, we also find that the transmission and distribution miles variable is no longer statistically significant; neither is the business condition variable of the number of electric customers served.

[15] The trend coefficient estimate of 0.0013 had an associated T-Statistic of 0.487, well below the T-Statistic threshold magnitude of 1.645 typically used to determine significance.

The table below shows the model estimates of the PEG-R model specification restricted to the more applicable time period of 2002-2009.

Table 3-4 Model Estimates of the PEG-R Model

Model Variable	Coefficient Estimate	T-Statistic
Constant	12.589	409.941
Capital Input Price (K)	0.502	103.368
Total Customers (N)	0.847	18.872
Tx and Dx Miles (M)	0.008	0.162
% Dx Mains not Cast Iron or Bare Steel	-0.478	-6.070
Number of Electric Customers Served	-.001	-0.675
K*K	0.030	0.911
N*N	-0.166	-1.694
M*M	-0.229	-2.266
K*N	-0.037	-3.770
K*M	0.037	3.962
N*M	0.192	2.483
Trend	**0.0013**	**0.487**

Since the line mile variable is statistically insignificant in the above model, PSE investigated modifying the PEG-R specification to substitute a variable based on volume delivered rather than line miles. Volumes are one of the primary billing determinants in gas distribution and most TFP and cost function models include volumes in their specification.

The econometric cost model defining residential and commercial volumes as an output is provided in the following table. Again, this uses the more applicable time period of 2002-2009 and keeps all other PEG-R variables the same, except for the substitution of residential and commercial volumes for transmission and distribution line miles. The volume variable (0.0607) is statistically significant at a 90% confidence level. The reader will notice the time trend, once again, is quite different from the trend used in the PEG-R Report. It is similar to the model discussed previously. It equals 0.10% and is a statistically insignificant.

Table 3-5 Model Estimates of the PEG-R Model (with volume variable)

Model Variable	Coefficient Estimate	T-Statistic
Constant	12.579	480.643
Capital Input Price (K)	0.506	90.885
Total Customers (N)	0.785	29.660
Residential and Commercial Volumes (V)	0.0607	1.805
% Dx Mains not Cast Iron or Bare Steel	-0.333	-6.463
Number of Electric Customers Served	-0.003	-1.683
K*K	-0.055	-1.277
N*N	-0.094	-0.686
V*V	-0.288	-1.680
K*N	-0.028	-1.839
K*V	0.038	2.368
N*V	0.175	1.156
Trend	**0.0010**	**0.460**

Given these two models, the consistency in the trend estimate, and the likelihood that the technology trend of the industry is approaching zero in recent years, PSE finds that a more applicable and conservative estimate for the technology trend is 0.00% rather than PEG-R's estimate of 0.63% (see Table 3-2 at [J]). This revised trend estimate lowers the expected TFP and further enhances the TFP performance of EGD relative to this expected TFP estimate. It provides a more accurate comparison to EGD's measured TFP growth during the incentive regulation period. The revised backcast table based on PSE's estimate of the trend variable is provided in the following table.

Table 3-6 EGD's TFP Projections using Updated 2007 Method and More Applicable Time Period for Dataset

TFP Growth Projections from Econometric Research for EGD

Sample Years	2005-2007	2008-2010
Elasticity Estimates from PEG-R cost model		
Customers [A]	0.716	0.716
Line Miles [B]	0.167	0.167
Sum of Output Elasticities [C = A + B]	0.883	0.883
Output Index Weights from PEG-R cost model		
Customers [D = A/C]	0.811	0.811
Line Miles [E = B/C]	0.189	0.189
Subindex Growth based on PEG-R Report		
Customer [F]	2.84%	1.83%
Line Miles [G]	0.52%	0.49%
Output Growth (elasticity weighted)		
[H = D*F + E*G]	2.40%	1.58%
Returns to Scale [I = (1-C)*H	0.28%	0.18%
Technology Change [J]	0.00%	0.00%
TFP Projection "2007 Method" and new trend [K = J+I]	**0.28%**	**0.18%**

The table below summarizes the predicted TFP with no business condition variables and the newly estimated trend variable. EGD outperforms its predicted annual TFP trend by 0.75% in 2008-2010 and by 1.01% in 2005-2007.

Table 3-7 EGD's Measured and Expected TFP using Updated 2007 Method and Similar Time Period

Time Period	Expected TFP Growth	Measured TFP Growth	Difference	Conclusion Based on Results in Table
2005-2007	0.28%	1.29%	1.01%	**EGD outperformed the industry by a large margin**
2008-2010	0.18%	0.93%	0.75%	**EGD outperformed the industry by a large margin**

3.3 Enhancement #3: Incorporate the Beginning Level Cost Efficiency of Enbridge

The third way in which the PEG-R TFP backcast method can be improved is to incorporate the cost efficiency level of the company when examining expected TFP trends. Gas distributors that are more efficient will have less room to trim costs and increase their TFP trend. Conversely, firms that start with relatively more inefficiency have more ability to cut costs, and thus have a more rapid TFP trend.

The previously referenced *Review of Network Economics* journal article states that "[a] decline (increase) in inefficiency will accelerate (decelerate) TFP growth."[16] Similarly, in the November 2007 report the authors state:

> TFP will grow (decline) to the extent that X inefficiency diminishes (increases). The potential of a company for TFP growth from this source is greater the greater is its current level of operating inefficiency. Evidence on operating efficiency can be produced using statistical benchmarking.[17]

[16] Lowry, Mark N. and Lullit Getachew, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry," *Review of Network Economics* Volume 8, Issue 4 – December 2009, page 331.

[17] See page 7 of the November 2007 report to the Ontario Energy Board, "Rate Adjustment Indexes for Ontario's Natural Gas Utilities."

Thus, a proper TFP projection or prediction over the examined incentive regulation time period would have examined the relative cost efficiency of EGD. The PEG-R Report emphasizes a number of times that the TFP backcasts are applicable to a distributor of <u>average efficiency</u>.[18] The available efficiency improvements relative to the sample are necessary to accurately predict TFP trends.

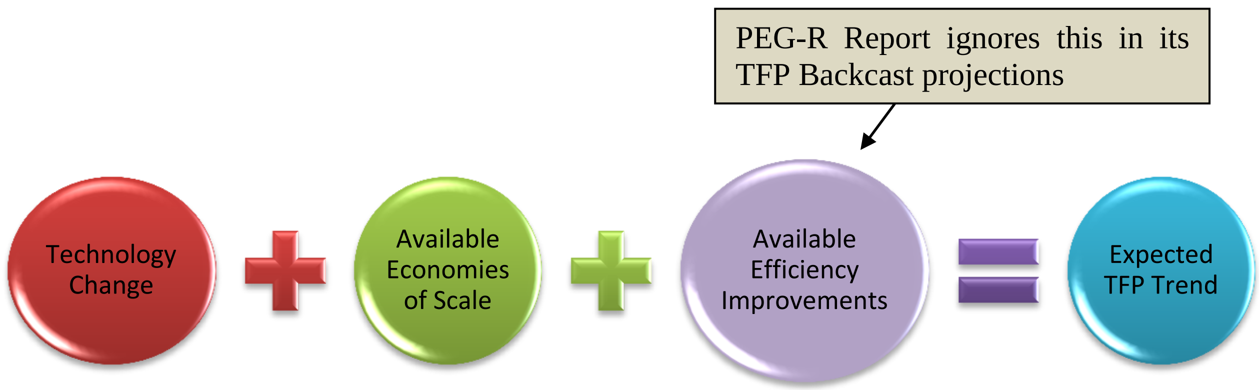


Figure 3-1 TFP Components

The Ontario Energy Board has recognized the relationship of cost efficiency and productivity trends. In its 3rd Generation Incentive Regulation plan for power distributors, stretch factors are tied to annual operation, maintenance, and administrative (OM&A) cost efficiency benchmarking scores. The benchmarking scores are based on industry quartile unit cost rankings and econometric benchmarking results. The stretch factors range from 0.2% for firms found to be top quartile and statistically significant cost performers, to 0.6% for firms found to be bottom quartile and statistically inferior performers. All other firms receive a stretch factor of 0.4%.

Operation and maintenance (O&M) spending can be most readily adjusted in the short-run. Whereas most capital expenses are fixed in the short-run, O&M spending levels are more flexible. It is logical that a firm that already has efficient O&M spending will have a lower potential to reduce this spending in the short-run. The starting O&M efficiency level needs to be considered when determining an expected TFP trend. Concentric finds EGD to be an efficient O&M cost performer compared to other North American gas distributors. Thus, EGD has much less room to boost its TFP trend by cutting its short-run O&M expenses.[19]

PSE has conducted research that quantifies the relationship between O&M cost efficiency and short-run TFP trends. Our findings indicate that TFP trends are significantly affected by the beginning year O&M cost efficiency. The relationship is such that firms found to have O&M per customer costs which are in the top quartile have short-run TFP trends which are lower than other firms.

[18] See, e.g., page 99 of the PEG-R Report.

[19] See Concentric's *Benchmarking Study*, most notably the O&M per customer findings of EGD relative to the industry.

For this research we limited our analysis to PEG-R's sample of 34 U.S. gas distributors. We then ranked this sample by the O&M cost per customer for each year beginning in 2002.[20] PSE identified the firms found to be in the top quartile (top eight firms) for each year through 2007. We then calculated 2-year TFP growth rates, 2-year customer growth rates, 2-year gas mile growth rates, and 2-year percentage of non-cast iron and bare steel growth rates for 2002-2009. This includes six observations per distributor: 2002-2004, 2003-2005, 2004-2006, 2005-2007, 2006-2008, and 2007-2009.

These variables allowed us to develop an econometric model that estimated the impacts of these variables and the top quartile designation on 2-year TFP trends. Our findings support many of PEG-R's assertions, such as the claim that growth rate in customers and gas miles will be positively correlated with TFP growth.

We also found that having a top quartile O&M per customer designation in the beginning year will tend to reduce TFP growth by 1.98%. Another finding was that the change in the percentage of non-cast iron and bare steel does not statistically influence TFP trends. In fact, the coefficient estimate is negative, which is the opposite of what PEG-R assumes when it includes business condition variables in its TFP backcasts (see Section 3.1). Additionally, the constant term supports PSE's finding in Section 3.2 that there is not a statistically significant technology trend when recent years are analyzed in determining expected TFP trends.

The table below provides the regression results and the finding that the O&M efficiency level has a strong and statistically significant influence on TFP trends. Furthermore, the change in the percentage of non-cast iron and bare steel mains is not a statistically significant driver of TFP trends, and in fact has a negative coefficient estimate, implying that growth in this term reduces (rather than increases) short-run TFP trends.

Table 3-8 Regression Results for O&M Efficiency Level

Model Variable	Coefficient Estimate	T-Statistic
Constant	-0.001	-0.287
2-Year Customer Growth	0.557	3.587
2-Year Line Mile Growth	0.465	2.788
2-Year % Non-Cast Iron and Bare Steel Growth	-0.104	-0.637
Beginning Year Top Quartile	**-0.0198**	**-4.407**

Our results suggest that average annual TFP growth is reduced by approximately 1.98% relative to a normal firm if the firm is designated as a top quartile O&M cost performer on the basis of O&M per customer rankings. This finding is statistically significant at a 99% confidence level. Concentric's benchmarking results found in their January 2012 report *Benchmarking Study*, indicate that EGD is a strong O&M cost performer. Concentric finds EGD's 2009 O&M expenses per customer to be third in their sample, which consists of 35 U.S. and Canadian gas utilities. This is certainly a top quartile industry ranking. To account for this higher level of

[20] 2002 is the first year where SNL Energy makes available O&M breakdowns to enable us to mimic the O&M definition used by PEG-R in the PEG-R Report.

O&M cost efficiency, we find that 1.98% should be subtracted from the expected TFP trends of EGD.

Table 3-9 displays the expected 2008-2010 TFP trend for EGD using the finding that top quartile O&M cost performance lowers short-run annual TFP trends by 1.98%. The table provides very strong evidence of EGD outperforming the industry expected TFP trends during both 2005-2007 and 2008-2010. In fact, the difference appears to be well in excess of 200 basis points.

Table 3-9 EGD's TFP using 2007 Method and Appropriate Comparison Period, Assuming Superior Cost Performer

Time Period	Expected TFP Growth (with all PSE Enhancements)	Measured TFP Growth	Difference	Conclusion Based on Results in Table
2005-2007	-1.70%	1.29%	2.99%	**EGD outperformed industry by a large margin**
2008-2010	-1.80%	0.93%	2.73%	**EGD outperformed industry by a large margin**

We note that EGD appears to have significantly outperformed the expected annual TFP trends computed using PEG-R's TFP backcast methodology if PSE's three enhancements are made. The first enhancement was to simply revert to the method PEG-R used in their 2007 report. The difference relative to the current methodology is that business condition variable changes are not incorporated into the TFP projections. As stated earlier, it is not logical to incorporate a variable that is expected to have a long term impact, and not a short term impact, in a short term projection of TFP. PEG-R came to this same conclusion in its 2007 report, and PSE updated and verified their research in this report.

The second enhancement was to estimate the econometric trend parameter using a more applicable time period. For various reasons, the technology trend variable, and thus the industry TFP rate, has declined over recent years. As the econometric dataset is limited to more closely reflect the time period being investigated, we will have a more applicable time trend estimate to insert into the TFP projection. We do note, however, the requirement to have enough observations in order to estimate a robust econometric model. This is why PSE examined a 2002-2009 dataset, which we were able to use to estimate a valid model with statistically significant first order variables (except the time trend, which we would expect to be close to zero).

The third enhancement was to account for the O&M cost efficiency level of EGD. Concentric found EGD to be a cost efficient firm with top quartile O&M per customer spending levels. This higher level of efficiency represents a challenge to EGD for TFP growth, because the company cannot easily lower its already efficient O&M expenses. This is an excellent "problem" to have.

By being more efficient EGD is saving its customers money. However, this challenge is one that analysts should be aware of and adjust for when computing expected TFP trends and evaluating the historical TFP performance of EGD relative to the industry.

3.4 Bias Estimate of PEG-R Methodology

The virtue of the three improvements suggested above can be seen by comparing the apparent bias in the original PEG-R methodology relative to the methodology as improved by PSE. This serves as an independent confirmation of the validity of PSE's suggested improvements to PEG-R's backcast (over and above the rationale already provided for the improvements in Sections 3.1 to 3.3 of this PSE Review). In this section we test the performance of our models by seeing how well they predict the actual outcomes they are attempting to model.

In performing this confirmation, PSE began by estimating the average 2007-2009 TFP trends of the 34 gas distributors cited in PEG-R's Report.[21] Without access to the actual data and methods used by PEG-R to calculate their TFP trends, we reiterate that this is a preliminary assessment. We attempted to replicate the data and methods used by PEG-R. We also used the sample of 34 U.S. gas distributors to provide consistency with PEG-R's analysis; however, this should not imply that PSE feels this is the best available group of utilities to compute EGD expected TFP trends.

PSE's estimate of the average annual TFP trends of the sampled 34 gas distributors *declined* by 0.77% from 2007 to 2009. The output quantity index, which used the same output weights as suggested by PEG-R, grew at an average annual rate of 0.50%.[22] The input quantity index grew at an average annual pace of 1.27%. Notice that a TFP trend is simply the change in an output index minus the change in an input index, so 0.50% - 1.27% = -0.77%.

The PEG-R TFP backcast methodology was implemented on the entire U.S. sample to determine what the average TFP backcast estimate would be for the sample. This is the same method used by PEG-R to evaluate the IR period TFP growth of EGD in the PEG-R Report. Recall that PEG-R included business condition variables, used a 1999-2009 sample timeframe, and did not account for the relative efficiency of each firm.

Using the PEG-R method, PSE estimates the average TFP backcast of the U.S. industry would increase annually by 0.94%. This is compared to the estimated TFP *decline* of 0.77% during that same period. This amounts to an observed upward bias of 1.71% in the PEG-R Report. Table 3-10 below summarizes these findings.

[21] We examine 2007-2009 because this is the most recent data available for EIA-176 data providing information on the number of customers and volumes for U.S. gas distributors during the time of the analysis by PSE. The 2009 end year also matches PEG-R's U.S. dataset allowing for consistency. 2010 EIA-176 data is now available.

[22] We used PEG-R's output definitions of customers and line miles and the weights used for these outputs. We did this for consistency despite our finding in Section 3.2 that volumes is probably a better output variable to use relative to line miles. Including volumes would certainly be more in line with historic measurements of TFP within the energy utility industry.

Table 3-10 Comparison of Measured and Average Industry TFP Backcasts (using PEG-R Method)

Time Period	Average Measured TFP Growth	Average TFP Backcast using 2011 PEG-R Methodology	Observed Bias
2007-2009	-0.77%	0.94%	**1.71%**

As observed in Table 3-10, there appears to be a large amount of bias in the PEG-R TFP backcast methodology as presented in the PEG-R Report. PSE's preliminary assessment of this bias is that PEG-R's method overstates expected 2007-2009 TFP growth by 1.71%. If the method were truly unbiased, we would expect the average TFP backcast to approximate the average measured TFP growth. Instead, the PEG-R method produces, on average, TFP growth that is significantly higher than the average observed value.

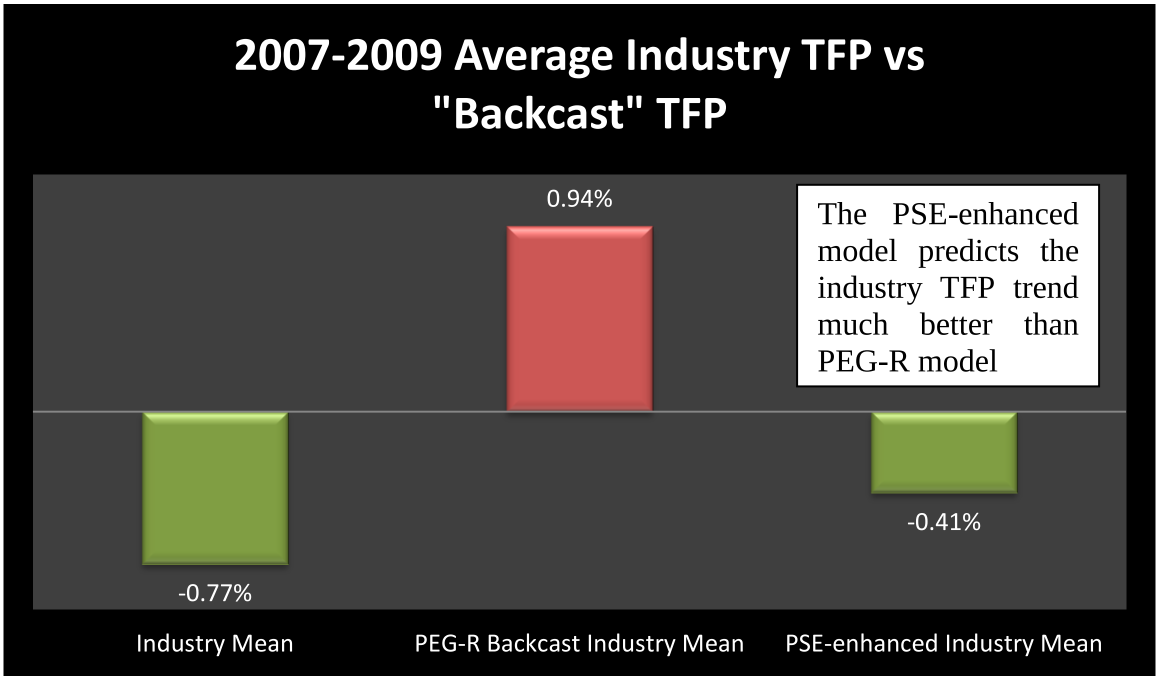
As an added check to PSE's suggested enhancements to the PEG-R method, found in Sections 3.1, 3.2, and 3.3, we tested the PSE-enhanced version of the TFP backcast to see if it provided less observed bias. Our analysis is that our method reduces the bias from 1.71% to 0.36%. This provides strong evidence that the methodological enhancements suggested by PSE are improvements and provide more reliable expected TFP values. It is also noteworthy that PSE's model still shows a slight upward bias, thus PSE's conclusions regarding expected TFP trends based on this model are likely to be conservative.

Table 3-11 below summarizes the PSE-enhanced TFP backcasts relative to the average TFP growth observed from 2007 to 2009.

Table 3-11 Comparison of Measured and Average Industry TFP Backcasts using PSE-Enhanced Methodology

Time Period	Average Measured TFP Growth	Average TFP Backcast using PSE Improvements	Observed Bias
2007-2009	-0.77%	-0.41%	**0.36%**

As observed in Table 3-10 and Table 3-11, the PSE-enhanced TFP backcasts are much more accurate and contain significantly less bias than the PEG-R method employed in the PEG-R Report. The PSE-enhanced version is only "off" by 0.36% relative to the measured average TFP trend, while the PEG-R method is off by 1.71%.



This evidence should put into doubt the current PEG-R method of determining expected TFP growth through the use of a long-run econometric model. It certainly appears that the PSE enhancements significantly improve the performance of the model and, thus provide much more accurate expected TFP trend estimates. Our analysis also raises important questions about using customized TFP expectations at all, rather than the more customary method of using an industry-wide peer group (or at least a large group) to fashion TFP expectations.

4 Comments on PEG-R's TFP Peer Group

In Chapter Six of the PEG-R Report, the backcast model results are supported through a comparison of EGD and Union to selected U.S. peer groups. PEG-R writes on page 109:

> Overall, we believe these comparisons with specific distributors identified as "peers" reinforce the conclusions of PEG-R's backcast model, which shows that EGD has greater opportunity to boost its TFP growth, and achieve incremental TFP gains, than does Union.

Later in this chapter we will discuss how a peer group consisting of only two or three utilities is inadequate and makes the analysis extremely vulnerable to outlier observations and low quality data. However, even if we take the comparisons presented by PEG-R at face value, the results actually appear to support PSE's findings in Chapter 3 that EGD outperformed its expected TFP trend during the examined incentive regulation period.

PEG-R used two separate peer group comparisons. PEG-R first began by comparing EGD's and Union's TFP trends with U.S. gas distributors operating under incentive regulation plans. The U.S. IR distributors used were Atlanta Gas Light, Bay State Gas, and Boston Gas. The calculated TFP trends from 2004-2009 varied considerably for the three utilities with an average TFP trend of 0.02%.

PEG-R also constructed a peer comparison with two other U.S. gas distributors. This second peer analysis compared EGD and Union with two other gas distributors, New Jersey Natural Gas and Washington Gas Light. Again the TFP results differed considerably for these two peer utilities, with an average TFP trend of 0.44%.[23]

The results of the two peer group comparisons appear to be very much in line with PSE's findings in Chapter 3 that EGD outperformed its expected TFP trend. EGD outperformed the U.S. IR utilities' TFP by 1.05% and the identified peer utilities by 0.63%. Note that PEG-R used a 2004-2009 time frame for the U.S. companies and a 2005-2010 time period for EGD.

Table 4-1 EGD's Measured and PEG-R Comparison TFP Trends

EGD TFP Growth	U.S. IR TFP Growth	EGD Difference from U.S. IR	U.S. Peer Comparisons	EGD Difference from Peer
1.07%	0.02%	**1.05%**	0.44%	**0.63%**

Despite this substantiation of PSE's findings that EGD outperformed its expected TFP trend, we believe developing peer groups consisting of only two or three utilities is insufficient and leaves

[23] These two utilities (New Jersey Natural Gas and Washington Gas Light) were selected on the basis of cluster analysis. It was assumed that Union Gas and EGD were peers in the analysis. This assumption and other assumptions should be further examined during the discovery process to determine their impact on the findings.

the research vulnerable to outlier observations and the possibility of poor quality data from a few utilities driving the analysis. PEG-R previously held this same view. In a separate report submitted to the Ontario Energy Board regarding the cost benchmarking of the power distribution industry, PEG-R wrote:

> As a practical manner, this means that it is desirable for benchmarks to be based on several years of data for several companies. In our experience, it is generally desirable for peer groups to have more than five members.[24]

Given that TFP trends are essentially measuring the relative cost efficiency of a firm in the last year to that same firm in the first year, unless a firm is substantially different than the industry there is no reason to depart from the conventional method of determining expected TFP trends. This conventional method relies on an industry-wide TFP trend, or on a substantially large peer group's TFP trend. This protects the researcher from making conclusions based on outlier observations and poor quality data.

PEG-R identified three variables that they found to be most relevant in determining expected TFP growth for EGD. These are the change in the number of customers, the change in kilometers of line, and the trend in the percentage of main that is not cast iron or bare steel.[25] The following figures present the changes in these three variables over the examined time period. These figures are based on data gathered by PSE from SNL Energy and thus are preliminary, based on our best guess of the variable definitions and data used by PEG-R. Once the discovery process is complete, we will be able to use the actual data used in the PEG-R analysis.[26]

PSE believes that these figures provide no strong evidence for departing from the conventional method of benchmarking TFP growth to industry or a large peer group average. To see why, consider the three figures shown below. The first figure displays EGD's relative ranking in customer growth rate over 2005-2009 to the U.S. sample of 34 gas distributors used in the PEG-R Report.[27] EGD is one of the faster growing utilities in the sample, in terms of customer additions. However, three other utilities are at or above the level of EGD and there are a number of gas distributors with similar growth rates.

[24] "Benchmarking the Costs of Ontario Power Distributors," March 20, 2008, p. 18, found at:

http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0268/PEG_Final_Benchmarking_Report_20080320.pdf

[25] See page 143 of the PEG-R Report. The peer group selection was based on the changes in four variables (customer numbers, miles of main, number of electric customers, and percent of distribution main not constructed of cast iron or bare steel). Since EGD does not serve electric customers and this has not changed, only three of the variables are relevant to the company according to PEG-R.

[26] PSE is not endorsing the PEG-R data or sample as the best available.

[27] We compare the 2005-2009 growth rates of the companies to EGD's 2005-2010 growth rates calculated in the PEG-R Report.

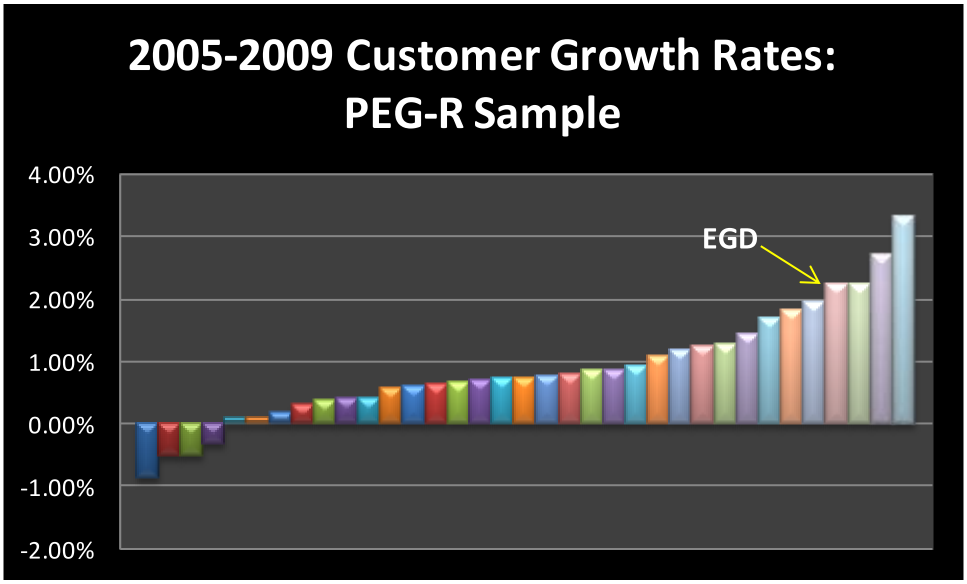


Figure 4-1 EGD's Relative Ranking in Customer Growth Rate from 2005-2009

Figure 4-2 displays EGD's annual growth rate in the length of mains relative to the U.S. sample. Contrary to the growth in customers, EGD's line growth has been on the lower end of the sample spectrum. This serves to balance out the TFP advantages found in the customer growth figure.

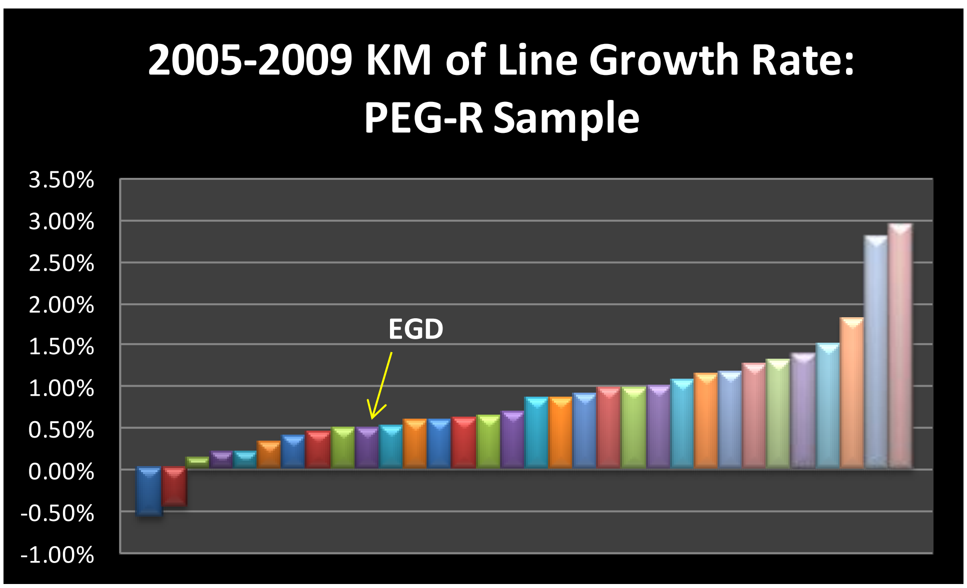


Figure 4-2 EGD's Annual Growth Rate in the Length of Mains

The next figure displays the annual change in the percentage of non-cast iron or bare steel in total distribution mains. The PEG-R Report claims that higher TFP growth rates should result from higher replacement rates of cast iron and bare steel. While PSE does not see solid evidence for this claim in determining short-run TFP trends, if the PEG-R claim were true then EGD would be disadvantaged in its TFP trend, as its percentage of non-cast iron or bare steel is growing slower than most in the U.S. sample.[28]

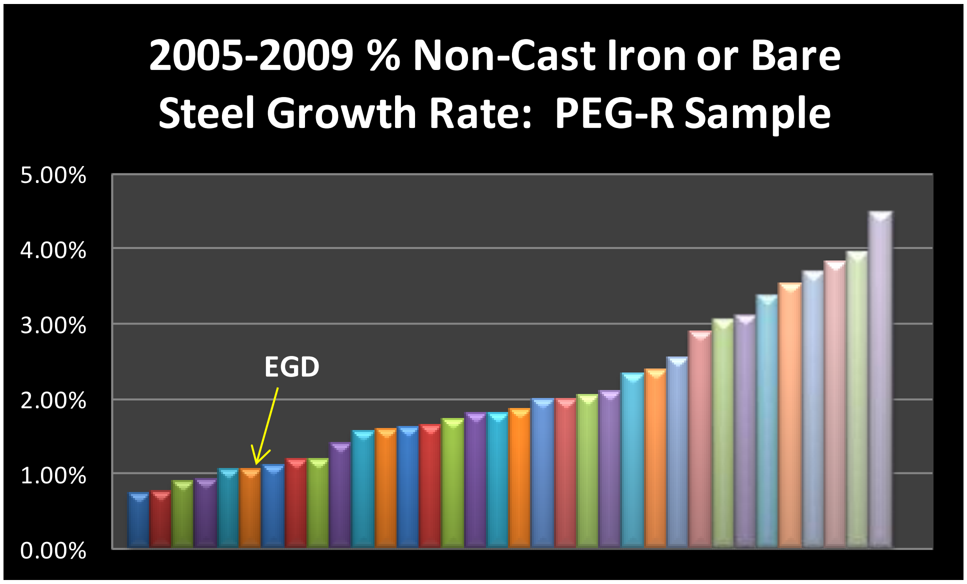
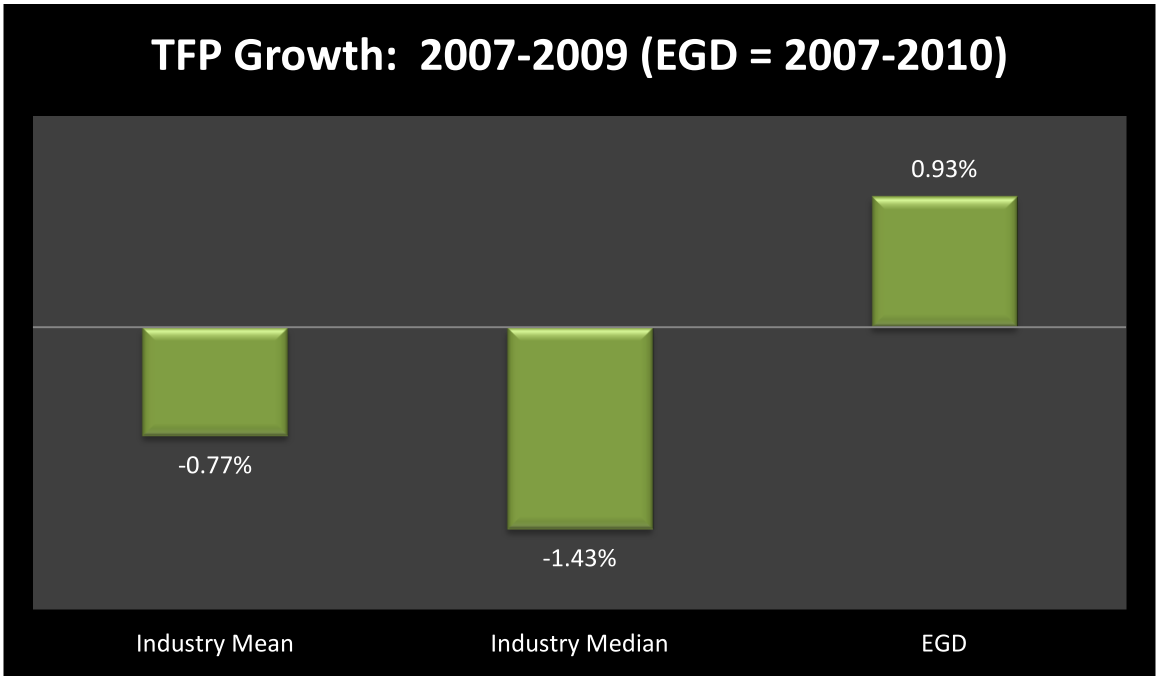


Figure 4-3 Annual Change in the Percentage of Non-cast Iron or Bare Steel in Total Distribution Mains

As displayed in the three figures above, EGD is certainly not an outlier in the three relevant variables identified by PEG-R as driving TFP growth. In fact, in two out of three of these variables EGD is actually disadvantaged. The rationale for departing from a larger peer group or the U.S. industry based TFP comparison is not evident from our preliminary analysis. A large peer group or industry analysis would provide more stable and unbiased results.

PSE attempted to replicate the TFP trends for the PEG-R sample based on their TFP calculation methods (again, we do not judge these methods at this time). Without access to the actual data values and exact methods used by PEG-R, this replication is only approximate. Our preliminary findings are that in recent years, the industry average and median TFP trend has been negative. We compare this negative U.S. industry trend to EGD's measured performance of 0.93% in the graph below.

[28] It does appear true, however, that in the long run total costs will be reduced by transitioning mains from cast iron and bare steel. This likely provides evidence for increased capital spending to accelerate this transition. While short run costs and capital spending will likely increase, according to PEG-R's econometric findings this will probably pay dividends in the long run.



This strong performance has resulted in lower gas delivery rates for customers and lower total costs for EGD. We should caution, however, that outperforming the industry by almost 200 basis points per year cannot continue indefinitely. It is likely that these strong TFP performances, combined with EGD's current low level of O&M spending per customer (see Concentric's *Benchmarking Study*) will necessitate future TFP trends to more closely mimic standard industry trends. However, EGD's customers will continue to benefit from these higher than normal 2005-2010 TFP trends well into the future, as these productivity gains are now embedded into the cost structure of EGD.

5 Implications for the "Backcast" X-Factor

It is useful to investigate EGD's X-factor for 2008-2010 in light of the PSE-enhanced expected TFP and input price experience. This assessment of the incentive regulation plan is important to determine if EGD benefitted from an X-factor that was too low, or if its gas customers benefited from an X-factor that was too high. We conduct this "backcast" X-factor analysis using PEG-R's methodology supplemented by the enhancements found in this report.

This analysis is meant to only examine what the historical X-factor should have been, now that the historical information is available. Naturally, at the time the X-factor was calibrated this information was not available. This research is not meant to prescribe a future X-factor but merely inform what a proper X-factor would have been for 2008-2010, given the now-available information.

EGD is currently regulated based on a revenue-per-customer cap mechanism. This is a type of incentive regulation plan due to the external nature of the allowed annual revenue escalations. Annual allowed revenue requirements are calculated mainly through a pre-set formula which incorporates economy-wide inflationary measurements and customer counts.[29] These items are external to the firm and not under its control. The current adjustment formula for the distribution revenue requirement in each year of the incentive regulation plan is:

$$DRR_t = \left(\frac{DRR_{t-1} - (Y_{t-1} + Z_{t-1})}{C_{t-1}}\right) * (1 + P * I) * C_t + Y_t + Z_t$$

Where:

DRR = the distribution revenue requirement
t = the rate year
C = the average number of customers
P = the inflation coefficient
I = the inflation index
Y = pass-throughs at cost of service
Z = exogenous factors

Of particular importance in the above adjustment formula is the means by which the previous years' revenue requirement is escalated. Essentially the escalation is accomplished through multiplying the previous year's revenue requirement by the customer growth ratio (C_t/C_{t-1}) and an adjusted economy-wide inflation factor. Within this inflation factor is an implicit adjustment for items such as expected productivity, industry input price differentials, and a stretch factor. These items are referred to as the "X-factor." The X-factor in the above formula is equal to one minus the inflation coefficient multiplied by the inflation index.

$$X = 1 - P*I$$

[29] The inflation rate used in the current IR plan is based on the Canadian GDP IPI (FDD).

5.1 X-Factor Mathematical Foundations

The rationale for incentive regulation including an X-factor is founded on economic cost theory. We start with a commonly accepted equation in economics, that cost equals input prices times input quantities.

Cost (C) = Input Prices (W) * Input Quantities (Q) **[Equation 1]**

Equation 1 can be translated into the annual trend in cost by adding the trend in input prices and the trend in input quantities.

trend C = trend W + trend Q **[Equation 2]**

Assuming the goal of a revenue cap per customer incentive regulation plan is to have a utility's allowed revenues track its expected costs (or revenue requirement), we can substitute revenues (R) into the left-hand side of Equation 2.

trend R = trend W + trend Q **[Equation 3]**

The next step is to simply subtract the trend in customers (N) from both sides of Equation 3.

trend R – trend N = trend W + trend Q – trend N **[Equation 4]**

The left-hand side of Equation 4 will then equal the trend in the revenue per customer (RPC), and the right hand side can be rearranged as shown below.

trend RPC = trend W – (trend N –trend Q) **[Equation 5]**

Rather than the actual industry input price trend, the Canadian GDP-IPI (we'll refer to this as "I") is used in Enbridge's incentive regulation equation. If we add and subtract I from the right hand side of Equation 5 we get equation 6.

trend RPC = I + (trend W – I) – (trend N –trend Q) **[Equation 6]**

The last adjustment needed before defining the X-factor for an RPC incentive regulation plan is to adjust for the trend in the output index. PEG-R incorporates both customers and line miles as outputs based on their cost elasticity weights to determine the expected TFP trend. We do this by simply adding and subtracting the trend in the output index, which includes both customers and line miles (Y), from the right-hand side of Equation 6.

trend RPC = I + (trend W – I) – (trend Y – trend Q) – (trend N - trend Y) **[Equation 7]**

Notice that the term (trend Y – trend Q) is the definition of the TFP trend. The term (trend W – I) is the input price differential (IP) between the industry input prices faced by EGD and the GDP-IPI trend used in the calculation. The last term is the difference between the customer trend and the output index trend (OD).

trend RPC = I – (TFP + OD – IP) **[Equation 8]**

The term in the parenthesis (TFP + OD – IP) is the appropriate X-factor for an RPC incentive regulation plan, such that:

trend RPC = I – X **[Equation 9]**

5.2 Backcast X-Factor and IR Plan X-Factor

We can now examine what an appropriate X-factor for EGD would have been, given the actual industry conditions and results from 2008-2010. In Section 3, the expected TFP of EGD during 2008-2010 was calculated to be -1.80%. On page 63 of the PEG-R report, the price differential between the industry input price trend and the GDP-IPI is stated to be 0.45%. Using Equation 8 above, IP thus equals 0.45%. The output differential between the cost elasticity weighted output index and the customer-only index for EGD during 2008-2010 equals 0.25% (1.83% - 1.58%).[30]

Table 5-1 Revenue per Customer X-Factor Calculations

EGD Expected TFP for 2008-2010 [TFP]	-1.80%
Customer and Output Index Differential [OD]	0.25%
GDP-IPI Differential [IP]	0.45%
Backcast X-Factor [TFP +OD - IP]	-2.00%

According to Table 2 of the PEG-R Report, EGD's average measured X-factor during 2008-2010 equaled 0.72%. The calculated Backcast X-factor of -2.00% provides evidence that EGD faced a very challenging X-Factor during 2008-2010, based on the actual experience of the U.S. gas industry. Its measured X-factor was 2.72% greater than what the Backcast X-factor would suggest to be appropriate. This reinforces the finding that EGD performed exceptionally well during the 2008-2010 time period and that its customers benefited from this performance.

Table 5-2 EGD's Measured X-Factor

IR Measured X-Factor	Backcast X-Factor	Difference
0.72%	-2.00%	**2.72%**

[30] This information can be found and calculated on Table 21 of the PEG-R Report. EGD customer growth is equal to 1.83%. The output index growth is calculated by taking the output index weights of 81.05% and 18.95% for customers and line miles, respectively, and multiplying by the growth in each output 1.83% and 0.49%, respectively.

6 Findings and Conclusions

In this Review, PSE has conducted an examination of PEG-R's methodology used to calculate EGD's benchmark TFP trend. A more thorough investigation should be undertaken once the PEG-R Report is filed and the discovery process begins. Our preliminary assessment has uncovered that the methods used by PEG-R in fashioning the expected TFP trends of EGD can be substantially improved.

Using the improved methodology, our preliminary analysis finds that EGD *outperformed* its expected TFP trend during the examined IR period (See Table 3-9). EGD's annual measured TFP trend of 0.93% is over 200 basis points greater than the expected trend we estimated in Chapter Three of this report. This refutes PEG-R's conclusion that EGD has scope to increase its TFP trend beyond the measured 0.93%. In fact, the opposite is likely to be true.

Our preliminary research in this document provides strong evidence that EGD's productivity trend was well above most of its peers and provided strong value to stakeholders. This rapid productivity trend has provided consumers with lower rates than would have normally been the case.

6.1 Improvements to the PEG-R Method

PSE has uncovered **three primary causes** for why PEG-R's expected TFP trend is inflated.[31] The **first cause** is PEG-R's inclusion of business condition variables, in particular the percentage of cast iron and bare steel, in the TFP backcast calculation. By including the business condition variables into the analysis, PEG-R is assuming that long run cost savings resulting from less cast iron and bare steel pipes will all be realized in the short-run, in this case three years.

The conclusion that by spending more money on main replacement, a utility's short-run TFP is expected to increase appears faulty at face value. While based on PEG-R's estimated *long run* cost function, it does appear that lowering the percentage of cast iron and bare steel mains reduces costs, this in no way necessitates a *short term* cost savings that would boost expected TFP trends.

PEG-R personnel in past reports to the Ontario Energy Board have stated the rationale of not including business condition variables in such an analysis, and have even conducted regression analysis to support this claim. PSE has verified these previous findings. No evidence in the PEG-R Report was put forth to contradict these prior claims. Until convincing evidence is provided that the observed long run cost implications of converting cast iron and bare steel mains can be translated into short run cost savings, the inclusion of business condition variables into the TFP backcast methodology is not warranted.

The **second cause** for the inflation of PEG-R's expected TFP trend is that the estimates are based on a dataset starting in 1999 and ending in 2009. On the other hand, the dataset used to compute EGD's measured TFP trend covers the years 2005 to 2010.

[31] This statement does not mean there are not other issues with PEG-R's method.

The gas industry has seen a slowdown in productivity. Aged capital has necessitated replacement, and the recession has reduced output growth. Using a dataset that is not reflective of these conditions will inherently bias the analysis against a utility being evaluated during the more recent time period. PSE used a more applicable and recent dataset spanning from 2002-2009. Our findings are that the technology trend is no longer statistically significant (and even reverses signs) when a more applicable time period is used. Thus, we have set the technology trend estimate to zero in our analysis.

The **third cause** for an inflated PEG-R EGD expected TFP trend was not incorporating the strong O&M cost performance of the firm. Other sampled firms have a larger ability to reduce costs through improving the efficiency of their operations. Given EGD's current strong O&M cost efficiency, as cited in a report prepared by Concentric Energy Advisors, they have much less available potential to improve. PSE estimates that firms that start with top quartile O&M per customer cost efficiency are expected to have 1.98% lower annual TFP trends for the subsequent two years.

In Section 3.4 of this review, we tested the validity of the PSE enhancements relative to the method found in the PEG-R Report. We did this by comparing the measured U.S. sample average TFP trends to the average produced by each method. We found that the PEG-R method, as detailed in the PEG-R Report, appears to have an upward bias in the expected TFP level of 1.71%. When PSE's suggested enhancements are introduced, the bias is substantially reduced to 0.36%. This provides solid evidence for the reasonableness and increased accuracy of the enhancements suggested to calculating expected TFP trends.

6.2 Peer Group Analysis and X-Factor Analysis

PSE also believes the peer group analysis found in Chapter Six of the PEG-R Report, while supporting PSE's findings of slower expected TFP growth for EGD, includes far too few utilities to be reliable. There is little reason to depart from the more conventional method of determining expected TFP growth through an industry-wide or large peer group TFP study. PEG-R identified three relevant TFP trend determinants in its analysis. These are the changes in the number of customers, line length, and the percentage of non-cast iron and bare steel. As shown in Chapter Four, EGD is certainly not unusual in any of these TFP determinants. In fact, for two out of the three determinants, EGD actually faces more challenging conditions during 2008-2010 than the U.S. industry sample used by PEG-R (although we dispute the relevance of the percentage of non-cast iron and bare steel).

The expected TFP growth calculated by PSE during the 2008-2010 period is combined with the PEG-R findings of challenging input prices relative to the Canadian GDP-IPI to determine a Backcasted X-Factor. PSE's findings that the implicit X-Factor of 0.72% faced by EGD during 2008-2010 is 2.72% above the appropriate X-Factor given the company's TFP trend, output growth, and input price inflation. Given proper X-Factor mechanics and the benefit of hindsight, the X-Factor during 2008-2010 would have been set at -2.00%.

6.3 Summary

In summary, the PEG-R Report includes a number of accurate and positive findings in the assessment of incentive regulation and EGD's performance within that framework. However, our analysis indicates that PEG-R's calculations of EGD's "expected" total factor productivity are inflated. This results in PEG-R's inaccurate conclusion that there is substantial room for EGD to boost its total factor productivity (TFP). We find that EGD has significantly outperformed the U.S. industry to the benefit of its customers. These cost savings are now reflected in EGD's cost structure and will help to keep gas delivery rates low. It is unlikely, however, that with EGD's historic high TFP trends and top quartile cost efficiency that this rapid productivity pace can be maintained indefinitely.

The implicit X-factor of 0.72% faced by EGD was far more challenging than what the historical data would have suggested. PSE estimates the appropriate Backcast X-Factor to be -2.00%. This provided very strong value to EGD's customers; even while the company faced increasing input price pressures, the gas delivery prices actually declined during the 2008-2010 time period. The bottom line is that PEG-R's claim that EGD has room to improve its TFP is incorrect: EGD has actually outperformed its expected TFP, and is likely to trend closer to that expected TFP in the future.

About PSE's Economics and Market Research Group

Founded in 1974, PSE is a full-service consulting firm. PSE's benchmarking experience includes research for regulatory purposes and utility management improvement. Our benchmarking team consists of economists, planning and design engineers, rate and financial analysts, communications infrastructure consultants, and smart grid technology experts. In addition to our statistical cost research, PSE's Economics and Market Research group has expertise in the areas of demand response, energy efficiency, value-based reliability planning, T&D reliability benchmarking, merger valuations, load forecasting, load research, survey design, alternative regulation, and cost of service studies. For more information on PSE and a full list of services, visit our website at www.powersystem.org.

About the Authors

Steve Fenrick, Leader - Benchmarking and Economic Studies

Mr. Fenrick has over a decade of consulting experience in the evaluation of utility performance. He leads PSE's benchmarking and economic study practice areas. He has provided expert witness testimony on performance benchmarking and authored numerous reports on the topic. He is the conference chair for a semi-annual EUCI conference on measuring and improving the cost and reliability performance of energy utility distributors. Mr. Fenrick has evaluated performance relating to electric and gas distribution, power transmission, power plant performance, and water distribution. These evaluations have been conducted for utilities, regulatory agencies, and consumer advocates. Mr. Fenrick has a Master's degree in Applied Economics from the University of Wisconsin and a BS in economics from the same university.

Lullit Getachew, Senior Economist

Dr. Getachew has experience in conducting research and analysis in support of benchmarking projects for energy utilities. She has written a number of academic journal articles on benchmarking and performance evaluation. She has also prepared studies and reports for performance-based regulation of transmission and distribution energy businesses, undertaken total and operation cost benchmarking, prepared reports for rate settlements, and marketed flexibility in rate designs. Dr. Getachew earned her doctorate in Economics at Rice University, her Master of Arts in Law and Diplomacy at the Fletcher School at Tufts University, and her BA *magna cum laude* from Mount Holyoke College.

CHANGE IN ACCOUNTING METHODOLOGY – PENSION EXPENSE

Purpose

1. Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") requests the Board for approval to recover pension expense on an accrual basis as determined by its actuaries, Mercer (Canada) Ltd. ("Mercer"), in accordance with US GAAP commencing January 1, 2013 in a manner appropriate for a rate regulated entity.

2. Enbridge proposes to switch from the cash basis of pension expense for rate regulated accounting to the accrual basis of expense. This would align the reporting for financial reporting purposes and rate making purposes which would provide more transparency and consistency for the users of the financial statement.

Background

3. Under the current incentive regulation term ("IR"), the regulated utility operations of the Company would recover pension expense based on amounts paid/contributions made to the pension plans as this is what affects earnings (i.e., cash basis of expense). To date Enbridge has not had to make such contributions and as such has not had to recover any amounts for rate-making purposes, pending a Board decision with respect to the 2012 pension Z-factor request.

4. The Company is proposing to switch from the cash basis of pension expense to the accrual basis of pension expense and as such would like to recover pension expense for rate-making purposes on the accrual basis.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
A. Patel
B. Yuzwa

<u>Benefits</u>

5. Accounting bodies have generally tried to match expenses to the proper time period in which the costs are incurred and revenues that are generated from those expenses. In the case of pension expense, the expense should be recognized in the period in which employees render services to qualify for employee future benefits. According to the CICA handbook:

> The objective of accounting for the cost of Employee Future Benefits is to recognize a liability and a cost in the reporting period in which an employee has provided the service that gives rise to the benefits. [1]

Current treatment of recovering pension expense on a cash basis does not factor in the period in which employee services were rendered, but rather the cash outlay in a year from employer contributions that has accumulated from years of employee services rendered. Further current treatment of recovering pension expense on a cash basis is unfair to current ratepayers as they bear the burden of an accumulation of years of employee services rather than current year employee services.

6. Ultimately at the time the pension plan is wound up, pension expense under the cash basis and accrual basis would be the same. However the pattern in which these expenses are incurred differ under both scenarios as the cash basis expense only arises when Enbridge is required to make contributions to the plan as stipulated by legislative requirements set by the Financial Services Commission of Ontario and calculated in accordance with actuarial standards/rules. Accrual basis of expense on the other hand arises annually as employee services are rendered.

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[1] *CICA Handbook Section 3461, paragraph .002*

Therefore the accrual basis of expense is fair to ratepayers and also provides for less volatility in rates.

7. The Company has considered the impact to the ratepayer over the next five years if it were to switch from cash basis of pension expense to the accrual basis of pension expense.

Ratepayer Impact

8. In the baseline scenario results, as prepared by Enbridge's actuary Mercer, (refer to Mercer Summary), the total expense from 2013 to 2017 under the accrual basis is $106.6M versus $145.2M under the cash basis expense resulting in $38.6M less to be collected from the ratepayers over the next IR term[2].

9. In addition to an accrual basis of expense resulting in less to be collected from the ratepayer EGD is also of the view that an accrual basis of expense will result in less volatility to the ratepayer in both economy upturns and downturns resulting in greater rate stability. Appendix A shows the expense sensitivity of positive and negative asset and liability shocks to both the accrual basis and cash basis.

- The cost variance to the ratepayer under the 20% positive asset shock and 20% negative asset shock is less under the accrual basis than the cash basis by $41.0M and $15.8M respectively; and
- The cost variance to the ratepayer under the 1% positive liability shock and 1% negative liability shock is less under the accrual basis than the cash basis by $80.8M and $62.8M respectively.

[2] Based on plan experience to the end of August 31, 2011

Earnings Stability

10. Switching from a cash basis of expense to an accrual basis of expense will not impact earnings stability as long as Enbridge's rate recovery mechanism mirrors the basis for accounting for pension expense that affects earnings.

USGAAP versus CGAAP

11. The Company has used CGAAP as the basis of accounting when determining pension expense however by January 1, 2013 Enbridge will be under USGAAP.

12. Enbridge has considered the difference between the two accounting standards as it relates to the accrual method of pension expense, namely US GAAP and CGAAP, and the only significant differences are the treatment of unamortized transitional assets which under USGAAP are not permitted to be amortized, and the treatment of net actuarial gains/losses and prior service costs, which are a part of accumulated other comprehensive income under US GAAP versus pension liability under CGAAP. However, under both USGAAP and CGAAP the net actuarial gains/losses and prior service costs are amortized to pension expense. With the adoption of USGAAP the unamortized transitional assets will be written off to retained earnings (2 years worth of amortization as the balance under CGAAP would have been fully amortized by the end of 2013), and the unamortized actuarial gains/losses and prior service costs will be reclassified to accumulated other comprehensive income and amortized into pension expense over the expected average remaining service life. Therefore as a result of Enbridge adopting US GAAP ratepayers are not materially impacted.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
A. Patel
B. Yuzwa

MERCER SUMMARY

The figures in the chart below are based on the "Estimated 2013-2017 Cash Funding Costs" and "Estimated 2013-2017 Accrual Costs" reports ("the Mercer reports") prepared by Enbridge's actuary, Mercer. Please refer to the Mercer reports filed as the appendices to this exhibit for details.

Baseline

Results calculated by Mercer assuming economic and demographic experience unfold exactly as expected.

Baseline Results (2013 to 2017 cumulative):

	Cash Funding Costs	US GAAP Accrual P&L Charge
Cumulative Total	$145.2M	$106.6M

Shock to Equity Market

Results assume that equity markets return 20% more or less than baseline assumptions.

Positive Asset Shock in 2013 (+20% Equity Return):

	Cash Funding Costs		US GAAP Accrual P&L Charge	
	Total Cash Cost	Change from Baseline	US GAAP P&L Charge	Change from Baseline
Cumulative Total	$65.6M	($79.4)M	$68.0M	($38.4)M

Negative Asset Shock in 2013 (-20% Equity Return):

	Cash Funding Costs		US GAAP Accrual P&L Charge	
	Total Cash Cost	Change from Baseline	US GAAP P&L Charge	Change from Baseline
Cumulative Total	$203.6M	$58.6M	$149.4M	$42.8M

Yield Curve Shift

Results assume a year-end 2013 parallel shift in the yield curve which liability discount rates are based on. It is assumed this change would not impact the fixed income portion of the plan's assets.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
A. Patel
B. Yuzwa

Positive Liability Shock in 2013 (+1% Shift in Yield Curve):

	Cash Funding Costs		US GAAP Accrual P&L Charge	
	Total Cash Cost	Change from Baseline	US GAAP P&L Charge	Change from Baseline
Cumulative Total	$38.2M	($106.9)M	$80.4M	($26.1)M

Negative Liability Shock in 2013 (-1% Shift in Yield Curve):

	Cash Funding Costs		US GAAP Accrual P&L Charge	
	Total Cash Cost	Change from Baseline	US GAAP P&L Charge	Change from Baseline
Cumulative Total	$226.3M	$81.1M	$124.9M	$18.3M

UPDATED EVIDENCE

13. Enbridge received an update from Mercer (“updated Mercer report)” using plan experience to the end of March 31, 2012 as compared to the originally filed evidence which used plan experience to the end of August 31, 2011. The updated report has higher pension expense costs under both the accrual and cash basis of pension expense as the update reflects the economic environment as at March 31, 2012 as well as updated actuarial data. Specifically the increase in pension expense was due to:

    - October estimates were based on extrapolations of the December 31, 2010 actuarial valuation. The update reflects the actuarial valuation completed as of December 31, 2011. Using this valuation means plan membership data as well as the most up-to-date payroll data was updated.
    - Solvency funding discount rates and accounting discount rates have dropped by approximately 0.50% and 0.70% respectively. This reduction in discount rates results in an increase in liabilities.

    These increases were partially offset by financial markets performing slightly better then expected between August 31, 2011, and March 31, 2012.

14. Using the updated Mercer report, pension expense costs from 2013 to 2017 under the accrual basis are \$143.1M versus \$161.9M under the cash basis of expense.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
C. Patel
D. Yuzwa

15. Enbridge's position to switch from the cash basis of pension expense to the accrual basis of pension expense still holds as the benefits, impact to ratepayers, and earnings stability as discussed in the original filing are still valid. Appendix – A Updated shows the expense sensitivity of positive and negative asset and liability shocks to both the accrual basis and cash basis using the updated figures per Mercer.

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
C. Patel
D. Yuzwa

MERCER SUMMARY - UPDATED

The figures in the chart below are based on the “Updated Estimated 2013-2017 Cash Funding Costs – EGD Pension Plans” and “Updated Estimated 2013-2017 Accrual Costs – EGD Pension Plans” reports (the “updated Mercer reports”) prepared by Enbridge’s actuary, Mercer (Canada) Limited (“Mercer”). Please refer to the updated Mercer reports filed as the appendices to this exhibit for details.

Baseline

Results calculated by Mercer assuming economic and demographic experience unfold exactly as expected.

Baseline Results (2013 to 2017 cumulative):

	Cash Funding Costs	US GAAP Accrual P&L Charge
Cumulative Total	$161.9M	$143.1M

Shock to Equity Market

Results assume that equity markets return 20% more or less than baseline assumptions.

Positive Asset Shock in 2013 (+20% Equity Return):

	Cash Funding Costs		US GAAP Accrual P&L Charge	
	Total Cash Cost	Change from Baseline	US GAAP P&L Charge	Change from Baseline
Cumulative Total	$86.9M	($75.0)M	$99.1M	($44.0)M

Negative Asset Shock in 2013 (-20% Equity Return):

	Cash Funding Costs		US GAAP Accrual P&L Charge	
	Total Cash Cost	Change from Baseline	US GAAP P&L Charge	Change from Baseline
Cumulative Total	$223.9M	$62.0M	$190.2M	$47.1M

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
C. Patel
D. Yuzwa

Yield Curve Shift

Results assume a year-end 2013 parallel shift in the yield curve which liability discount rates are based on. It is assumed this change would not impact the fixed income portion of the plan's assets.

Positive Liability Shock in 2013 (+1% Shift in Yield Curve):

	Cash Funding Costs		US GAAP Accrual P&L Charge	
	Total Cash Cost	Change from Baseline	US GAAP P&L Charge	Change from Baseline
Cumulative Total	$58.9M	($103.0)M	$114.0M	($29.1)M

Negative Liability Shock in 2013 (-1% Shift in Yield Curve):

	Cash Funding Costs		US GAAP Accrual P&L Charge	
	Total Cash Cost	Change from Baseline	US GAAP P&L Charge	Change from Baseline
Cumulative Total	$246.1M	$84.2M	$165.0M	$21.9M

Witnesses: K. Culbert
J. Jozsa
S. Kancharla
C. Patel
D. Yuzwa

RATE BASE - CAPITAL BUDGET

1. The purpose of this evidence is to present the 2013 Budget for capital expenditures. The "B" series of exhibits provide the Ontario Energy Board (the "Board") with information and variance explanations concerning, 2011 Historic Year, 2012 Estimate Year, and 2013 Test Year capital expenditures and customer additions. Appendix 1 provides a detailed breakdown of 2007 Board Approved Budget, 2011 Historic, 2012 Estimate and 2013 Budget.

2013 Budget

2. The 2013 Capital Budget is a consolidation of the traditional 'grassroots' budget prepared by all departments within Enbridge Gas Distribution ("Enbridge" or the "Company") in accordance with the guidelines and assumptions setout in the Budget Letter. The budget was developed in consideration of the Company's key business objectives of a continued focus on safety and reliability, customer service, and adherence to legislative and regulatory requirements. The Capital Budget was reviewed and approved by the Executive Management Team (the "EMT").

3. At Exhibit B1, Tab 3, Schedule 1, the Company describes how it has undertaken the development of an Asset Plan which, when filed as Exhibit B2, Tab 2, Schedule 1, will identify the distribution system capital requirements to address customer growth, reinforcement, integrity and reliability, and relocation needs over a ten year period. As described in the Asset Plan evidence, the plan is a rolling plan and will be updated each year. The to be filed Asset Plan covers the period from 2012 to 2021. The Company expects to file the Asset Plan in March 2012.

Witnesses: L. Au
S. Kancharla
D. Kelly
R. Lei

4. The key function and utility of a methodolologically developed Asset Plan is the prioritization of capital requirements . The Asset Plan sets out the nature, timing and anticipated cost of the capital requirements for the distribution system for each year of the Asset Plan's ten year term. It will fully detail the capital requirements asscociated with the distribution assets for the Test Year and the Bridge Year. As management of distribution assets are the Company's core business, the Asset Plan idenitifies the majority of the Company's capital requirements.

5. Capital requirements that are not included in the Asset Plan include those required for Information Technology, Storage, Facilities and other non-distribution asset capital needs. This Asset Plan however will certainly inform the decision making in respect of these other capital requirements.

6. While a detailed Asset Plan was not prepared for 2011 the capital requirement needs of the Company in 2011 can be identified by asset category and consequently can be categorized in a fashion similar to the Asset Plan for ease of reference. Table 1 on the following page has characterized the 2011 capital budget in this fashion.

7. Table 1 on the following page shows the planned expenditures for the Company are $398.0 million in 2011, $404.5 million in 2012 and $483.9 million in 2013. These expenditures are those required to meet the needs identified and prioritzed by the Asset Plan which responds to customer needs including safety whichcontinues to be a primary focus for the Company. This includes ensuring and maintaining pipeline integrity and compliance with applicable technical legislation, establishing policies and procedures to ensure a safe work environment for employees and a safe and reliable distribution system for customers and the public all in conformance with utility best practices. In addition to ongoing safety

initiatives, the Company has included other initiatives that support the Asset Plan and Integrity Management in its capital requirements. These initiatives are included in Exhibit B1, Tab 2, Schedule 1.

Table 1
Summary of Capital Expenditures and Customer Additions

	Col 1	Col 2	Col 3	Col 4
Exhibit References	B5-T2-S1	B5-T2-S1 B5-T2-S3	B4-T2-S1 B4-T2-S3	B3-T2-S1 B3-T2-S3
($Millions)	Board Approved Budget 2007	Historic Year 2011	Estimate Year 2012	Test Year Budget 2013
Customer Related Distribution Plant	134.2	133.4	118.8	138.6
NGV Rental Equipment	0.2	0.2	0.3	0.3
System Improvements and Upgrades	149.1	165.5	188.2	257.5
General and Other Plant	30.0	68.8	71.2	67.4
Underground Storage Plant	4.5	30.1	26.0	20.1
Total Capital Expenditures	318.0	398.0	404.5	483.9
Customer Additions	46,228	36,753	37,927	38,896
Average ($Dollars) Cost per Customer Addition including Power Generation	$ 2,903	$ 3,630	$ 3,132	$ 3,563
Average ($Dollars) Cost per Customer Addition excluding Power Generation	$ 2,276	$ 3,085	$ 3,088	$ 3,201

8. As shown in Appendix 1 of this schedule, customer related plant includes the cost of mains, services and meters associated with the customer growth the Company continues to experience. It also includes estimates to supply Power Generation projects totaling $20.0 million in 2011, $1.8 million in 2012 and $14.0 million in 2013.

9. In addition to the Power Generation projects, the figures in Table 1 above, include estimates for projects which also have or will require specific Leave to Construct ("LTC") applications. These LTC Projects total $5.0 million in 2011, $26.9 million in 2012 and $57.1 million in 2013. The LTC projects, which include potential power generation facilities and large reinforcement and replacement mains projects, will

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need to receive separate approval by the Board. These projects are discussed at Exhibit B1, Tab 3, Schedule 3, LTC Projects and are also included in Exhibit B1, Tab 2, Schedule 2, Listing of Projects over $500,000.

10. System Improvements and Upgrades includes relocation and replacement mains as well as reinforcements. It also includes all safety and integrity programs associated with the Company's assets. These can be associated with services, regulators and/or meters as shown in Appendix 1. Additional details of these requirements are contained in the Asset Plan at Exhibit B2, Tab 2, Schedule 1. The capital requirement for System Improvements and Upgrades is $165.5 million in 2011, $188.2 million in 2012 and $257.5 million in 2013. Projects costing more than $500,000 are listed at Exhibit B1, Tab 2, Schedule 2.

<u>2011 Historic Comparison to 2007 Board Approved</u>

11. The 2011 Historic year is $398.0 million, which was $80.0 million higher than the 2007 Fiscal Board Approved Budget of $318.0 million. The Board in its EB-2006-0034 ADR settlement of 2007 capital expenditures allowed for a $300.0 million capital envelope, plus $18.0 million for the Portland Energy Centre. It was left to Company management to determine which projects it would pursue in 2007 except for the $18.0 million allocated to Portlands Energy Centre. The division of the $300.0 million capital amount in the ADR settlement has been created for internal purposes and not specifically approved by the Board at the individual capital element level.

12. Explanations of the major variances have been provided at Exhibit B5, Tab 2, Schedule 1. The major variances contributing to this variance are as follows on Table 2:

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Table 2 - 2011 Historic vs. 2007 Board Approved: Major Variance

2011 vs 2007 Board Approved ($Millions)		Related evidence
Storage requirements	25.6	B1-2-2 and B1-5-1
Technical Training Facility	18.0	B1-2-2
Computer and communication requirements	16.7	B1-2-2 and B1-4-1
System improvement requirements	12.5	B1-2-2
General plant including furniture, fleet, tools	4.1	
Technical Training Initiatives	3.9	B1-2-2
Customer related distribution plant	(0.8)	
Overall increase	**80.0**	

i. Storage Operations capital requirements in 2011 increased relative to 2007 primarily due to requirements to enhance the integrity of gas inventory measurement and to comply with mandated regulations. These include the storage pool metering replacement project. The intent of this project is to replace and upgrade all storage pool metering to include bi-directional, ultrasonic flow measurement, on-line gas composition analysis and moisture measurement to meet current accepted standards of the AGA and/or Measurement Canada. Additional projects include observation wells, 3D Seismic survey of storage wells, and modifications required to comply with air and noise emissions standards;

ii. Capital expenditures in 2011 include the requirement for a new multipurpose facility to meet the joint needs of Technical Training and Central Region East Operations. This facility will allow the Company to actively develop and cross-train its employees through various initiatives such as the Operations Technician Training program. Furthermore, it will provide a better environment for learning, help the Company satisfy its long term training needs; and allow us to train all our workers (employees and contractors). Furthermore, the training facility will enable the company to achieve several objectives. This includes providing employees with job specific training. Secondly, it will provide a controlled and safe environment for the evaluation of technical competency. And, thirdly, it will enable the organization to demonstrate compliance with increased scrutiny on employee qualifications e.g. Operator Qualification. This project to be completed mid-2012 will see the consolidation of several existing facilities into one site. The site will include a one acre "Streetscape" where employees are trained on real life simulations in a safe and controlled environment and will be provided with comprehensive, theoretical and practical training on critical tools and equipment. Construction of this facility supports the Company's objective of enhancing its strong safety culture;

iii. Computer and communication equipment capital expenditures are essential to support required upgrades to IT systems and infrastructure. These upgrades are necessary to sustain the reliability, security, availability, and supportability of systems and infrastructure that are critical to the operations for the Company;

iv. Capital expenditures for system improvement and upgrades were higher primarily due to higher levels of cast iron replacement and relocation activity. The cast iron replacement program is required to ensure the safety and reliability of the distribution system. Replacements are prioritized using several factors; the Company begins with a determination of the highest priority section of main, and then designs a replacement project for that neighbourhood. Projects are further prioritized by coordinating the replacement projects with the City’s capital works, primarily Toronto Transportation and Toronto Water. Relocation projects are necessary to meet the needs of other utilities and municipalities, they require the Company to relocate the main to accommodate their requirements;

v. Other general plant requirements including structures and improvements, office furniture, transportation fleet and tools increased in 2011 compared to 2007, primarily due to new office furniture and equipment to replace aging items and to meet new requirements and on-going improvements to structures;

vi. Capital requirements for the Technical Training Initiative; including the development of training materials for Field and Office staff, utilizing new tools and technology such as eLearning modules (Computer based training), instruction led courses and practical hands on scenarios. Gap analysis has identified over 300 training modules required to be developed to respond to development needs, remedial training requirements, changes resulting from projects and continous improvement to ensure a safe and competent workforce; and

vii. Capital expenditures for customer related distribution plant decreased in 2011 as compared to 2007, due to lower customer additions.

<u>2012 Estimate Comparison to 2011 Historic</u>

13. The 2012 Estimate of capital expenditures is $404.5 million which is $6.5 million, or 1.6% over the 2011 Historic of $398.0 million. Detailed explanations of the variances have been provided at Exhibit B4, Tab 2, Schedule 1. The major drivers contributing to this variance are as follows on Table 3:

Table 3 - 2012 Estimate vs. 2011 Historic: Major Variance

2012 Estimate vs. 2011 Historic ($Millions)		Related evidence
LTC (Reinforcement projects)	22.1	B1-2-2 and B2-2-1
Other system improvement and upgrades	16.3	B1-2-2/B1-3-1/ B2-2-1
Computer and communication requirements	6.7	B1-2-2 and B1-4-1
Storage requirements	(4.1)	B1-2-2 and B1-5-1
General plant including structures,furniture, fleet, tools	(4.3)	
Customer related plant (including LTC power generation)	(14.6)	B1-2-2/B1-3-3/B4-2-3
Cast iron replacement program	(15.6)	B1-2-2 and B2-2-1
Overall increase	**6.5**	

i. Capital expenditures for system improvement capital increased in 2012 Estimate as compared to 2011 Historic primarily due to several Leave to Construct projects. These projects include the Greater Toronto Area (“GTA”), and the Angus and Alliston Reinforcement projects. The GTA project will address operational flexibility, pipeline integrity, security of supply and future growth requirements for the City of Toronto and GTA. The Angus and Alliston reinforcement projects will ensure that the Company meets the future capacity requirements for their respective areas;

ii. Other system improvements are higher in 2012, primarily due to integrity management projects including Records and GPS Strategy, Asset Risk Mitigation and the Revision of Damage Prevention Standards and Process. In addition, in 2012 the Company is required to complete additional relocation and reinforcement projects;

iii. Computers and Communication Equipment expenditures are essential to provide enhancements and required upgrades to existing hardware and software. This includesupgrades to desktop and laptop hardware, due to obsolesce, and upgrades to software as required by the vendor to ensure continued support. Infrastructure replacement of Nortel to CISCO due to technology obsolesce, email archiving for compliance and records management and Envision upgrades, to extend and enhance it's functionality to meet evolving business needs, maintain data integrity and improve data management governance;

iv. Storage Operations are lower in 2012 due to the completion of the pool metering upgrade for gas inventory measurement in 2011;

v. Other general plant including office furniture, transportation, fleet and tools is also lower in 2012, primarily due to lower requirements for transportation and heavy work equipment ;

vi. Customer related distribution plant is lower in 2012, primarily due to the completion of the York Energy Centre power generation project in 2011, this was partially offset by increased customer additions in 2012 relative to 2011. Customer additions are anticipated to increase 1,174 over 2011 levels givenpositive trends in the housing market and continued economic recovery;

vii. The Cast Iron replacement program is expected to be complete in 2012, the remainder of the program will install 41 kilometres of new main, 5,200 new services and abandon 60 kilometres of old main. In addition, all of the remaining Bare Steel mains located in the Niagara region are scheduled to be completed by the end of 2012.

<u>2013 Test Comparison to 2012 Estimate</u>

14. The 2013 Capital Budget is $483.9 million, which is $79.4 million more than the 2012 Estimate level. Detailed explanations of the variances have been provided at Exhibit B3, Tab 2 Schedule 1. The major elements of the 2013 Capital Budget are customer related distribution plant, system improvements and upgrades, general and other plant, and underground storage facilities. The major drivers contributing to the $79.4 million increase are shown as follows on Table 4 on the following page.

Table 4 - 2013 Budget vs. 2012 Estimate: Major Variance

2013 Test vs. 2012 Estimate ($Millions)		Related evidence
Other system improvement and upgrades	39.3	B1-2-2/B1-3-1/B2-2-1
LTC (Reinforcement and Replacement projects)	30.0	B1-2-2 and B1-3-3
Customer related plant (including LTC power generation)	19.8	B1-2-2 /B1-3-3/B3-2-3
General plant including structures,furniture, fleet, tools	(1.3)	
Computer and communication requirements	(2.5)	B1-2-2 and B1-4-1
Storage requirements	(5.9)	B1-2-2 and B1-5-1
Overall increase	**79.4**	

i. Other system improvements include safety and integrity programs that are essential to maintain a safe and reliable distribution system. The projects reflect the continuous commitment to meeting governing codes and standards as well as industry best practices. Capital expenditures for 2013 includes the on-going integrity management initiatives such as Records and GPS Strategy, Asset Risk Mitigation and Revision of Damage Prevention Standards. This category also includes asset plan initiatives that will assist management in making optimal decisions with respect to Enbridge's distribution system assets by balancing risks, operational performance and financial performance. These initiatives include Low Pressure Delivery Meter Set Program, Records Integrity Program, Don River Bridge Crossing Replacement, and the Isolation Valve Study & Installation Program. As well, the Company expects to complete additional relocation and replacement projects;

ii. Capital requirements increased due to three System Improvement Leave to Construct projects; the Ottawa Reinforcement, the GTA Reinforcement and Ottawa Innes Road Replacement Main. The Ottawa Reinforcement project allows Enbridge to meet the capacity requirements for this significant growth area, as well as pressure requirements at the Ottawa Gate Station. The GTA project will enhance network integrity, flexibility and the ability to dual-feed critical parts of the GTA. The Ottawa Innes Road Replacement project is a much needed replacement required to remove an existing system bottleneck, this replacement will facilitate other improvements in the system;

iii. Customer related capital has increased primarily due to several potential Power Generation projects which the Company will bring forward to the Board in LTC applications. In addition, the increase is partially due to the anticipated growth ofalmost one thousand customer additions in 2013 over 2012 levels. The customer growth is driven by stronger housing starts. Customer related capital is derived from the customer addition forecast that was prepared utilizing EBO 188 approved investment portfolio feasibility guidelines. Forecasts of customer additions are developed at a regional level based on a review of the Company's economic forecast and business plans, consultations between field personnel and building industry representatives, and the experience of the Company's regional management;

iv. Other general plant decrease in 2013 primarily due to the completion of the Technical Training and Operations Centre in 2012;

v. Computer and communication requirements decrease in 2013 primarily due to timing of expenditures. These expenditures are driven by information technology enhancements and necessary upgrades to existing software and hardware. The 2013 budget reflects the Company's requirements needed to support critical functions such as; EnVision systems, Customer Care applications, asset management and other technologies;

vi. Storage Operations decrease in 2013 primarily due to the completion of several projects in 2012. These include Observation Wells, Pool Metering and Sombra Station By-Pass. Storage Operations initiatives are crucial to ensure safety, environmental compliance and to increase system reliability.

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The following tables have been updated to reflect 2011 Actual which replaces 2011 Historic year data.

Updated Table 1
Summary of Capital Expenditures and Customer Additions

	Col 1	Col 2	Col 3	Col 4
Exhibit References	B5-T2-S1	B5-T2-S1 B5-T2-S3	B4-T2-S1 B4-T2-S3	B3-T2-S1 B3-T2-S3
($Millions)	Board Approved Budget 2007	Actual Year 2011	Estimate Year 2012	Test Year Budget 2013
Customer Related Distribution Plant	134.2	135.6	118.8	138.6
NGV Rental Equipment	0.2	-	0.3	0.3
System Improvements and Upgrades	149.1	160.5	188.2	257.5
General and Other Plant	30.0	73.0	71.2	67.4
Underground Storage Plant	4.5	30.1	26.0	20.1
Total Capital Expenditures	318.0	399.2	404.5	483.9
Customer Additions	46,228	35,657	37,927	38,896
Average ($Dollars) Cost per Customer Addition including Power Generation	$ 2,903	$ 3,803	$ 3,132	$ 3,563
Average ($Dollars) Cost per Customer Addition excluding Power Generation	$ 2,276	$ 3,247	$ 3,088	$ 3,201

Updated Table 2 - 2011 Actual vs. 2007 Board Approved: Major Variance

2011 vs 2007 Board Approved ($Millions)		Related evidence
Storage requirements	25.6	B1-2-2 and B1-5-1
Technical Training Facility	16.2	B1-2-2
Computer and communication requirements	20.4	B1-2-2 and B1-4-1
System improvement requirements	9.4	B1-2-2
General plant including furniture, fleet, tools	6.4	
Technical Training Initiatives	3.9	B1-2-2
Customer related distribution plant	(0.7)	
Overall increase	**81.2**	

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Updated Table 3 - 2012 Estimate vs. 2011 Actual: Major Variance

2012 Estimate vs. 2011 Actual ($Millions)		Related evidence
LTC (Reinforcement projects)	24.1	B1-2-2 and B2-2-1
Other system improvement and upgrades	16.4	B1-2-2/B1-3-1/ B2-2-1
Computer and communication requirements	3.0	B1-2-2 and B1-4-1
Storage requirements	(4.1)	B1-2-2 and B1-5-1
General plant including structures,furniture, fleet, tools	1.2	
Customer related plant (including LTC power generation)	(16.5)	B1-2-2/B1-3-3/B4-2-3
Cast iron replacement program	(18.8)	B1-2-2 and B2-2-1
Overall increase	**5.3**	

Other exhibits which have also been updated to reflect 2011 Actual capital expenditure data are as follows:

Schedule	Content
B1-2-2	Details of Capital Expenditures and Justification for Major Capital Projects over $500,000
B1-2-3	Capital Expenditures by Year (2007-2013 Table & 2008-2010 by initiative)
B4-2-1	Comparison of Utility Capital Expenditures 2012 Estimate and 2011 Actual
B4-2-2	2012 Capital Expenditures by Project (Projects Exceeding $500,000) Comparison of 2012 Estimate and 2011 Actual
B4-2-3	Gross Customer Additions and Average Cost per Customer Addition 2012 Estimate and 2011 Actual

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B5-2-1	Comparison of Utility Capital Expenditures 2011 Actaul and 2007 Board Approved
B5-2-2	2011 Capital Expenditures by Project (Projects Exceeding $500,000)
B5-2-3	Gross Customer Additions and Average Cost per Customer Addition 2011 Actual and 2011 Board Approved

Witnesses: L. Au
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UPDATED APPENDIX 1

COMPARISON OF CAPITAL EXPENDITURES
2007 BOARD APPROVED BUDGET, 2011 ACTUAL, 2012 ESTIMATE, AND 2013 BUDGET
(EXPRESSED IN $MILLION)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
Item No.		Board Approved Budget 2007	Actual 2011	Estimate 2012	Estimate 2012 Over/(Under) Actual 2011	Budget 2013	Budget 2013 Over/(Under) Estimate 201
A.	Customer Related						
1.1.1	Sales Mains	76.5	72.1	47.2	(24.9)	61.9	14.7
1.1.2	Services	46.2	55.9	58.9	3.0	64.1	5.2
1.1.3	Meters and Regulation	11.5	7.6	12.7	5.1	12.6	(0.1)
1.1.4	Customer Related Distribution Plant	134.2	135.6	118.8	(16.8)	138.6	19.8
1.1.5	NGV Rental Equipment	0.2	-	0.3	0.3	0.3	-
1.1	TOTAL CUSTOMER RELATED CAPITAL	134.4	135.6	119.1	(16.5)	138.9	19.8
B.	System Improvements and Upgrades						
1.2.1	Mains - Relocations	7.7	15.5	20.0	4.6	23.4	3.4
1.2.2	- Replacement	58.1	54.6	23.5	(31.1)	49.1	25.6
1.2.3	- Reinforcement	26.6	9.8	62.4	52.6	111.6	49.2
1.2.4	Total Improvement Mains	92.4	79.8	105.9	26.1	184.1	78.2
1.2.5	Services - Relays	17.3	45.9	43.2	(2.7)	20.2	(23.0)
1.2.6	Regulators - Refits	3.5	5.6	5.4	(0.2)	6.8	1.4
1.2.7	Measurement and Regulation	15.7	11.4	17.6	6.2	25.7	8.1
1.2.8	Meters	20.2	17.8	16.1	(1.7)	20.7	4.6
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	149.1	160.5	188.2	27.7	257.5	69.3
C.	General and Other Plant						
1.3.1	Land, Structures and Improvements	3.1	20.9	22.8	1.9	19.0	(3.8)
1.3.2	Office Furniture and Equipment	0.7	5.1	1.3	(3.8)	3.9	2.6
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	7.7	7.4	4.2	(3.2)	4.7	0.5
1.3.4	Tools and Work Equipment	1.2	1.9	2.2	0.3	1.6	(0.6)
1.3.5	Computers and Communication Equipment	17.3	37.7	40.7	3.0	38.2	(2.5)
1.3	TOTAL GENERAL AND OTHER PLANT	30.0	73.0	71.2	(1.8)	67.4	(3.8)
D.	Underground Storage Plant	4.5	30.1	26.0	(4.1)	20.1	(5.9)
E.	TOTAL CAPITAL EXPENDITURES	318.0	399.2	404.5	5.3	483.9	79.4

Note:
Variance explanations relating to 2011 Historic vs. 2007 Board Approved are found at Exhibit B5, Tab 2, Schedule 1, variance explanations related to 2012 Estimate vs. 2011 Historice are found at Exhibit B4, Tab 2, Schedule 1, and variance explanations relating to 2012 Estimate vs. 2013 Budget are found at Exhibit B3, Tab 2, Schedule 1.

Witnesses: L. Au
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Details of Capital Expenditures and Justification for Projects over $500.000
2011 through 2013
$(000's)

Line No.	Function / Project Name	In Service Date	Col 1 Actual 2011	Col 2 Forecast 2011	Col 3 Estimate 2012	Col 4 Test Year Budget 2013	Description/Justification
	Customer Related Distribution Plant						
1.	Power Generation Project A	Q2 2014					Enbridge has been asked to supply a proposed new gas fired cogeneration plant. The customer has submitted the proposal to the Ontario Power Authority (OPA) Combined Heat and Power (CHP IV) procurement program. If the proposal is accepted by the OPA, Enbridge will execute a service contract with the customer and file a LTC application with the Board in 2012. The requested gas in-service date is Q2 2014
2.	Power Generation Project B	Q1 2014					Enbridge has been asked to supply a proposed new gas fired cogeneration plant. The customer has submitted the proposal to the Ontario Power Authority (OPA) Combined Heat and Power (CHP IV) procurement program. If the proposal is accepted by the OPA, Enbridge will execute a service contract with the customer and file a LTC application with the Board in 2012. The requested gas in-service date is Q1 2014
3.	Power Generation Project C	Q1 2014					Enbridge has been asked to supply gas for a potential generation project. Pending a decision from the customer, Enbridge will execute a service contract and file a LTC application with the Board in 2012. The requested gas in-service date is Q1 2014.
	Sum of Power Generation Projects A, B and C				**1,460**	**14,040**	
4.	York Energy Centre Power Generation	Nov-11	20,049	20,029	250	-	Relates to a 396MW energy plant (LTC EB-2009-0187 application). Project involves 16.7 km of NPS 16XHP pipeline and associated facilities to deliver gas to the York Energy Center generating facility located in King Township.
5.	Everett Expansion Phase 1 Sales Main	Jul-11	1,376	1,113			The Everett Expansion project is complete and it was done to supply gas for 2 subdivisions that are estimated to be constructed in 2012/2013. There were 4 separate projects that totaled 6,889 m. The expansion was also completed to supply gas for subdivision further north into the town of Tioga. This will be a future project and currently there are no drawings or work request for this project.
	System Improvement Distribution Plant						
6.	Ottawa Reinforcement	Q1 2014	79	400	1,500	30,000	Approximately 20 km of NPS 24 XHP pipeline required to reinforce the Ottawa Distribution System. Required to allow the Company to meet area growth as well as pressure requirements at the Ottawa Gate Station.
7.	GTA Reinforcement	Dec 2015?	1,441	1,850	11,627	21,117	This project will address operational flexibility, pipeline integrity, security of supply and future growth needs of the City of Toronto and Greater Toronto Area. Required for pre-engineering, assessments, planning, network analysis and regulatory approval. Required to allow the Company to service area growth and to increase supply diversity and reliability. It will enhance the network integrity, flexibility and ability to dual feed critical parts of the GTA.
8.	Records and GPS Strategy	on going			3,000	12,500	Implement GPS gathering on critical mains during stand by work. Resurvey mains, headers and services which have inadequate or no records.
9.	Asset Risk Mitigation Initiative	on going			5,700	6,300	Required to mitigate risks related to our assets via in-line inspections and alternative current cathodic protection mitigation.
10.	Ottawa Innes Rd Replacement	Q4 2013				6,000	Replace 3.0 km of NPS 8 main with NPS 12, and remove an existing system bottleneck while ensuring a mandated inspection or elimination of high stress pipeline is completed by Dec 2013.
11.	BDCS Growth Initiative	Dec-13				5,934	The capital budget is required for future Business Development and Customer Strategy (BDCS) growth opportunities. Various projects are being reviewed and they will be assessed and reviewed by management as they arise for approval.
12.	Low Pressure Delivery Meter Set Program	Q3 and Q4			5,140	10,140	Study to enhance the knowledge of LP station condition and prioritize related upgrades, followed by required upgrade and replacement programs.

Details of Capital Expenditures and Justification for Projects over $500.000
2011 through 2013
$(000's)

Line No.	Function / Project Name	In Service Date	Col 1 Actual 2011	Col 2 Forecast 2011	Col 3 Estimate 2012	Col 4 Test Year Budget 2013	Description/Justification
13.	Technical Training Initiative	on going	4,993	3,900	3,700	3,647	Development of comprehensive training materials for field and office staff utilizing technologies such as eLearning modules (computer based training), instructor-led courses and practical hands-on scenarios. Gap anaylysis has identified over required 300 modules to respond to development needs, remedial training, change management and continuous improvement to ensure a safe and competent work force. Supporting tools and equipment for practical training are also required to ensure a safe and controlled environment in which to train our employees. To include training delivery, competency development and certification.
14.	Records Integrity Program	on going				3,523	Set of projects to identify and resolve various records related issues including clean up of data, refinement of processes and technology changes.
15.	Don River Bridge Replacement	Nov-13				3,500	Determine purpose need and timing of a replacement solution and implement the solution.
16.	Isolation Valve Study and Installation Program	Q3 and Q4				3,080	Study to validate the adequacy of the Company's current main line valve design requirements and any new/retrofit installations required associated with a change in the design requirement (including Automatic Shutoff and Remote Control Valves).
17.	Targeted Compression Couplings Pressure Containment Sleeve Program	Q3 and Q4				2,000	Reduce risk of injury to industry and public when excavating in areas with potential compression couplings. Identify targeted compression couplings and install pressure containment sleeves over these couplings.
18.	Revision Excess Flow Valve (EFV) policy	Q3 and Q4				1,500	EFVs are currently being installed in new services to single family homes. The intiative is to investigate expanding installation of EFVs to larger residential such as multi-family and small commercial customers.
19.	Amp Fitting Replacement program	Q3 and Q4				1,000	Study to examine leak rate trends and develop a replacement plan, followed by execution of the replacement plan. This initiative also includes an ongoing inspection program for amp fittings.
20.	Cast Iron Replacement Program	on going	43,832	40,580	25,190	942	Program to replace all remaining cast iron mains and their associated services. The rationale for replacement program is to ensure the safety and reliability of the distribution system.
21.	Stayner Reinforcement	Q3 2013				750	Install approx. 450m of 4XHP, 1300m of 4HP, 200m of 4 IP and new XHP-IP station. Required to bolster IP system pressures in this growing community.
22.	Revise Damage Prevention Standards and Processes	on going			1,550	520	Required to reduce risks associated with third party damages. Install excavation detection technology at targeted gate station and critical pipelines. Will also drive the oversight of third party excavators performing work near critical pipelines.
23.	Angus Reinforcement	Q4 2012			6,000		Approximately 10 Km of XHP pipeline required to facilitate the required future capacity of the Angus area.
24.	Alliston Reinforcement	Q4 2012	532	800	4,660		Approximately 9 Km of XHP pipeline required to facilitate the required future capacity of the Alliston area.
25.	Relocation Main - Davis Drive	May-12			4,000		Main relocation as required by York region municipality. Involves installation of 6"PE-3000m, 4" PE-1000m & 2" PE-1000m.
26.	Relocation Main - 9th Line (Markham Gate to Hoover Park)	Jul-12			3,000		Existing NPS 4 and NPS 8 XHP mains to be relocated and replaced by a single NPS 12 main to accommodate road widening.
27.	Torbram Relocation Main	Q4 2012	1,696	1,646	2,488		Rebillable relocation of NPS 12 XHP main for City of Mississauga.
28.	Kawartha Reinforcement- Phase 2 and 3	May-12	1,108	620	2,200		NPS 8 reinforcement to accommodate new ethanol plant "Kawartha Ethanol" in Havelock.
29.	Station B NPS 20	Q4 2012			2,000		Replacement and relocation of 700m NPS 20 downtown Toronto.
30.	Relocation Main- Bayly/Victoria	Q4 2012			2,000		Main relocation as required by the Region of Durham. Involves installation of 12" ST-2100m
31.	Peterborough Reinforcement	Sep-12			1,900		Install approximately 2.4km of NPS 8 on Preston Road (Mt Pleasant/Hwy 7).
32.	Sheridan Gate Station Bypass Relocation Main	Q2 2012			1,824		Relocation of pipe around the former Sheridan Gate Station site.
33.	Wyebridge Relocation Main	Q4 2012			1,800		Relocation of shallow pipe on easement to road allowance
34.	Relocation Main- Teston Rd/Pine Valley	Apr-12			1,300		Main relocation as required by the York Region. Involves installation of 12" - 800m

Details of Capital Expenditures and Justification for Projects over $500.000
2011 through 2013
$(000's)

Line No.	Function / Project Name	In Service Date	Col 1 Actual 2011	Col 2 Forecast 2011	Col 3 Estimate 2012	Col 4 Test Year Budget 2013	Description/Justification
35.	Relocation Main - Highway 7(Bayview to Warden)	Aug-12			1,200		Main relocation as required by the York Region. Involves installation of 6" - 1600m & 8" ST - 1000m
36.	Mayfield Road Reinforcement	Q4 2012			1,000		Approximately 2500m of 4 XHP on Mayfield east of Airport Rd to alleviate the sensitivity of the additional load on the IP.
37.	Relocation Main- Brock Road Phase 2	Q3 2012			980		Main relocation as required by the Region of Durham. Involves installation of 12" ST
38.	Scarborough Reinforcement	Q2 2012	(184)	659	751		Approximately 8 Km of NPS 16 main in the Scarborough and Markham required to meet the future demand in the Markham, Scarborough and Pickering area
39.	Hurontario Reinforcement	Q4 2012			750		Install approximately 1000m of NPS 6 ST HP on Hurontario (Steeles to County Court Blvd). Reinforcement necessary to maintain inlet pressures to stations due to organic growth.
40.	Anne Street (Barrie) Relocation Main	Q4 2012			750		Main relocation as required by the City of Barrie. Involves installation of 6" ST; 13.7m
41.	High Street (Barrie) Relocation Main	Q4 2012			600		Main relocation as required by the City of Barrie. Involves installation of 6" ST; 10m relocated; Additional relocation project originally scheduled for 2011 deferred to 2012 (includes 640 m 6"ST)
42.	Keele and McNaughton Reinforcement Main	Oct-12			560		Install approximately 1400M of NPS4 St on Keele from McNaughton to Teston. Required to bolster low system pressures.
43.	Brampton Rapid Transit - Satellite & Orbitor Relocation Main	Q4 2012			500		Main relocation as required by the City of Mississauga. 6" ST - 400m relocated 4" PE 700m
44.	Anderson Road Replacement	Q3 2011	2,291	2,287			Rush replacement of approx. 700m of NPS-16 XHP main from Hydro corridor N of Dolman Ridge Rd. to 700m N of Hydro corridor, along W side of Anderson Rd.
45.	Keele and Finch Relocation Main	Q4 2011	762	1,716			Relocation required by Toronto Transit Commission to accommodate Finch West subway station. Relocated approx 900m NPS 12 HP ST main.
46.	Hwy 35 South Relocation Main	Q1 2011	852	1,083			The MTO is widening highway 35 south of 7 for approximately 2.3km. Required by MTO to install 8" ST - 2000m
47.	Richmond Gate Reinforcement	Q3 2011	1,655	897			Reinforcement required to bolster overloaded systems in the central and west areas of Ottawa which have sustained significant rapid growth.
48.	Hwy 93 Relocation Main	Q4 2011	573	587			Main relocation as required by MTO. Involves installation of 6" ST - 2000m
49.	County Rd 88 Relocation Main	Q2 2011	525	525			Second phase of relocations for County of Simcoe widening of Cty Rd 88 west of Bradford. Required by Simcoe County to install 6"ST - 1500m
50.	New Westminister Replacement Main		2,695				
51.	Ottawa Gate Station		1,660				
52.	Oshawa Gate Station		1,180				
53.	Wasaga Beach Reinforcement		799				
54.	Haley Gate Station		752				
55.	In-line Inspection - Central region West		664				
56.	In-line Inspection - Eastern region		662				

Details of Capital Expenditures and Justification for Projects over $500.000
2011 through 2013
$(000's)

Line No.	Function / Project Name	In Service Date	Col 1 Actual 2011	Col 2 Forecast 2011	Col 3 Estimate 2012	Col 4 Test Year Budget 2013	Description/Justification
57.	Woodbine Station Replacement		533				
58.	York Region Rapid Transit/Highway 7 Relocation		514				
59.	Distribution Plant Listed above		91,039	78,692	99,380	126,493	
60.	Projects Less than $500K		122,193	135,040	107,573	163,962	
61.	Distribution Plant sub total		213,232	213,732	206,953	290,455	
	General Plant including Computer Equipment						
62.	Transportation and Heavy Work Equipment Replacements	on-going	7,379	8,230	4,221	4,667	Represents the cost of vehicle and equipment replacements based on corporate replacement policy.
63.	Technical Training and Operations Centre	Jun-12	16,197	18,000	13,000		The budget for this project is required to construct a multi-purpose facility to meet the joint needs of Technical Training and Central Region East Operations. This project will see the consolidation of the following existing facilities into one site: Markham construction and warehouse, Richmond Hill operations depot, VPC Engineering Materials Evaluation Centre and Technical Training in Pickering and Richmond Hill. The site will include a one acre "Streetscape" where employees are trained on real life simulations in a safe and controlled environment and will be provided with comprehensive, theoretical and practical training on critical tools and equipment. Construction of this facility supports the Company's objective of enhancing its strong safety culture.
64.	Casselman Operations Centre Replacement	Dec-12			1,300		The purchase and development of a building and site improvements is being proposed to replace a leased property that no longer meets the current and future special purpose needs of the operations function in that area.
65.	Pembroke Operations Centre Replacement	Jun-12			800		The purchase of the currently leased building and an adjacent site together with improvements is being proposed to meet the longer term needs than the current design that no longer meets the current and future special purpose needs of the operations function in that area.
66.	Kennedy Road Operations Centre Replacement	May-14			5,200	4,300	The existing Kennedy Road operations depot does not meet current building standards and operational requirements, has site limitations and no long term potential to expand the existing facility The building is over 40 years old and physically obsolete with the electrical and mechanical systems in need of a major retrofit and some of the building space inadequate for occupancy with barrier free accessibility being an issue. The property is also functionally obsolete as the building has exceeded allowable occupancy, the parking lot is congested, the operations yard requirements exceed the existing property with limited turn radius for construction equipment and the warehouse is undersized to house the necessary materials and equipment. The budget for this project includes the purchase of 6 acres of land and the construction of a 27,000 square foot building. Total project costs will be $13.3 million (including $3.8 million in 2014).

Details of Capital Expenditures and Justification for Projects over $500.000
2011 through 2013
$(000's)

Line No.	Function / Project Name	In Service Date	Col 1 Actual 2011	Col 2 Forecast 2011	Col 3 Estimate 2012	Col 4 Test Year Budget 2013	Description/Justification
67.	New Fleet Garage	May-14				8,500	The existing fleet garage is over 40 years old, does not meet current building standards and requires major improvements. The building shell, electrical and mechanical systems are in need of a major retrofit and windows and the roof will require a major capital improvement in the short term. The property is functionally obsolete as the heavy work equipment shop is undersized, there is an inadequate number and size of dedicated parking on site for vehicles and equipment and there are safety issues regarding the mixed use nature of the Victoria Park Complex for both industrial and office functions. The budget for this project includes the purchase of 4 acres of land and the construction of a 33,000 square foot building. Total project costs will be $12.2 million (including $3.7 million in 2014).
68.	New Meter Shop	Apr-13				2,000	This project is required to relocate the meter repair and testing shop from its current head office location to an appropriate location in a new leased facility. The vacated space can be transformed into office space to avoid significant lease costs for forecasted office space needs at head office. Leasehold improvements will be required to set up the operation in the new building and relocation of existing equipment.
69.	Colony Court Replacement	Jul-14				1,000	The existing operations depot at Colony Court in Brampton has served the region for the past 8 years and the lease expires in August 2013. As the organization has evolved, the office space and yard is no longer sufficient to accommodate the current and future needs of the operations function. The budget for this project is required for leasehold improvements in a new building.
70.	Envision Upgrade	2015				6,200	Upgrade of Work and Asset management system due to technology obsolesces and change in Vendor landscape.
71.	Leveraging SAP	on-going	3,389	6,017	4,900	4,500	Changes and enhancements required to stabilize SAP CIS to meeting growing business demands .
72.	SAP Hardware Refresh	2013				4,200	Purchase of new hardware (Servers and Storage) for SAP CIS. Existing SAP CIS hardware are coming off warranty at the end of 2012. The new purchase will keep technology current and at a supportable level.
73.	Reporting Analytics for Finance & Customer Care Department	on-going	465	1,297	1,450	1,500	Development of SAP business warehouse to support reporting and analytics for customer care and finance for enhanced decision making.
74.	Desktop Replacement	on-going			1,200	1,200	Necessary upgrades to existing desktop and laptop hardware due to obsolesce and support by vendors
75.	Capman/O&M Management Program	on-going	240	556	1,500	1,000	Development of capital management system to enable the organization to have visibility and greater control of capital and O&M spend.
76.	Microsoft Enterprise Agreement	on-going	1,062	1,060	950	950	Necessary upgrades to existing software to keep technology current and at a supportable level, in order to serve the Users and to ensure that systems do not become obsolete. Obsolete systems could pose risk to customer service, systems integrity, safety, and business itself.
77.	IT Request	on-going	770	676	650	800	All the miscellaneous hardware, software and accessories purchases.
78.	Remedy Upgrade	2012	913	1,100		756	Necessary upgrades to existing hardware and software to keep technology current and at a supportable level, in order to serve the Users and to ensure that systems do not become obsolete. Obsolete systems could pose risk to customer service, systems integrity, safety, and business itself.
79.	Infrastructure Replacement: Nortel to CISCO	2013	1,286	800	1,800	700	Replacement of Nortel Voice and Data due to technology obsolesce and which is no longer supported by the Vendor.
80.	Integrated Training Environment	2013	531			700	Creation of an end-to-end environment for meeting business training requirements. Systems include EnVision, SAP, and field force automation.
81.	SRM Enhancements	on-going	1,065	1,222	750	550	Enhancements to ensure data integrity, providing increased automation ,and additional reporting in order to serve the Users.

Details of Capital Expenditures and Justification for Projects over $500.000
2011 through 2013
$(000's)

Line No.	Function / Project Name	In Service Date	Col 1 Actual 2011	Col 2 Forecast 2011	Col 3 Estimate 2012	Col 4 Test Year Budget 2013	Description/Justification
82.	Supply Chain Management	on-going	612	559	1,000	500	Acquisition, development, and implementation of a warehouse management system to enhance business controls and enable EGD to better optimize its warehouse space and labor while minimizing transportation costs.
83.	Enterprise GIS Implementation/Enhancement	on-going	2,264	1,949	500	500	Software upgrades and incremental improvements to historical asset data solutions to improve functionality, data quality, accessibility and performance. Benefits include improved access to asset information that supports improved asset decision making for office and field staff.
84.	Asset Record Data capture	on-going			500	500	Analysis and development of systems and system enhancements to house the information to be captured to enhance records integrity and safety.
85.	Gas Molecule - 'nGARS	on-going	667	900	500	400	Enhance control, reporting and provide greater audit ability by replacing old spreadsheet system for a gas molecule costing and reconciliation system.
86.	Enterprise Email/Records Management	on-going			1,400	350	Implement email archiving for compliance and records management.
87.	EnMar Upgrade	on-going	1,197	1,061	700	300	Systems changes required to accommodate regulation mandated by Measurement Canada. Other enhancements also include changes to improve controls, reporting and transaction reliability, in addition to technology obsolesce as a result of lack of vendor support.
88.	Online Incident Management & Collaboration	on-going			500	200	Analysis, development, and implementation of a software solution to provide an integrated online Incident reporting system to manage emergency incident response.
89.	EnVision Enhancements	on-going	3,003	1,688	4,800		Work and Asset management system changes required on an ongoing basis to enhance and extend functionality to meet evolving business needs, maintain data integrity and improve data management governance.
90.	Microsoft Program	2012	1,122	1,545	2,200		Required upgrades to existing software to keep technology current and at a supportable level, in order to serve the Users and to ensure that systems do not become obsolete. Obsolete systems could pose risk to customer service, systems integrity, and safety.
91.	GMS/Open Link - Customer web Access	2012			900		Enhancements required to provide web access to customers as it related to the Gas Management System
92.	Oracle Database upgrade	2012			537		Necessary upgrades to existing software to keep technology current and at a supportable level, in order to serve the Users and to ensure that systems do not become obsolete. Obsolete systems could pose risk to customer service, systems integrity, safety, and business itself.
93.	CCSA (LBA Repatriation)	Jul-11	1,354	1,458			Repatriation of large billing accounts duties/functions/process from Accenture and related system changes that are required to complete the transition.
94.	Altra GMS Replacement	2011	734	933			Replace the two separate EGD Altra GMS systems with a consolidated system for physical gas deals and nominations.

Details of Capital Expenditures and Justification for Projects over $500.000
2011 through 2013
$(000's)

Line No.	Function / Project Name	In Service Date	Col 1 Actual 2011	Col 2 Forecast 2011	Col 3 Estimate 2012	Col 4 Test Year Budget 2013	Description/Justification
95.	Emissions Data Management & Reporting	2012	703	677			System development/changes required to support the Ontario GHG regulation as well as Environment Canada - National Pollutant Release Inventory reporting.
96.	SRM Analytics	2011	475	529			Enhancement to Stakeholder Relationship Management (SRM) system to meet the evolving needs of business process changes and enhancing reporting and query capabilities.
97.	Energy Supply Asset Transfer		745				
97.	General Plant Listed above		46,173	50,257	51,258	46,273	
98.	Projects less than $500K		22,814	16,338	15,171	17,432	
99.	General Plant sub total		68,987	66,595	66,429	63,705	
	Storage Plant						
100.	Tecumseh Office Facility	Dec2012/Dec2013			2,250	4,950	This is the cost of construction of new buildings in Gas Storage. This includes the cost of a new warehouse, fabrication shop and office as well as the cost of relocating the existing shop to the current warehouse building.
101.	Certificate of Approval Air and Noise Emissions	Dec-13	2,119	2,120	3,500	3,500	Make modifications to the exhaust stacks, cooler fans and turbochargers so as to comply with Ministry of Environment (MOE) Certificate of Approval for Tecumseh compressor station (Air and Noise emissions)
102.	MCC #1 Generator and Boiler Replacement	Dec-13				1,500	Replace and upsize the generator and boiler in MCC#1
103.	Purchase of Farm Properties	Nov2012/Dec2013		790	1,092	1,100	Purchase additional lands to ensure that there will be no residential noise and emissions receptor in close proximity to Tecumseh Corunna Compressor Station. Required for MOE compliance.
104.	Pipeline Integrity Program	Dec2012/Dec2013			1,000	1,000	Install the facilities that will be required to allow for pipeline inspection in the Mid and South Kimball gathering lines.
105.	Custody Measurement Upgrade at Dawn	Dec-13				1,000	Engineering review of facilities required for custody quality measurement at Dawn custody point.
106.	Plant Layout changes	Dec2012/Dec2013			750	750	Make a number of site changes at the Tecumseh, Sombra and Crowland compressor stations. They are intended to bring the sites up to meet current environmental and safety standards. The work will include moving fences, gate, parking areas, motor control centres and UPS. Will also include making site drainage changes and installing culverts into existing open drains.
107.	KVT Compressor Pressure Upgrade	Dec-13				750	Retrofit compressor to operate at higher pressures. Improves reliability in the event of unscheduled outages.
108.	Control Room Equipment changes	Dec-13			500	500	Relocate all control systems and related network infrastructure so as to relocate the Control Room to existing office building.
109.	Observation Wells	Dec-12	1,091	1,650	5,000		Completion of observation well drilling program that began in 2011. These wells are being drilled so as to provide a better understanding of the storage reservoirs and associated A1 structure.
110.	Replace/Upgrade Storage Pool Metering	Dec 12 and Dec 13	17,684	18,870	2,000		Upgrade required to enhance the integrity of gas inventory measurement.
111.	By-Pass of Sombra Station	Dec-12			1,000		Piping changes to eliminate the need to flow all gas through the Sombra station, even when not compressing gas.

Details of Capital Expenditures and Justification for Projects over $500.000
2011 through 2013
$(000's)

Line No.	Function / Project Name	In Service Date	Col 1 Actual 2011	Col 2 Forecast 2011	Col 3 Estimate 2012	Col 4 Test Year Budget 2013	Description/Justification
112.	KVT Upgrade K703	Dec-12	652	700	1,000		Upgrade mandated by Ministry of Environment. Required to reduce Nox emissions.
113.	Mid Kimball/South Kimball Road Crossing	Oct-12			750		Pipeline integrity assessment of the Mid and South Kimball pool and gathering systems.
114.	3D Seismic - Dow Moore/Coveny/Black Creek	Dec-11	1,707	2,017			Required to enhance gas inventory measurement. Involves the delineation of four storage pools.
115.	Phase II - Reservoir Simulation		512				
115.	Storage Plant Listed above		23,765	26,147	18,842	15,050	
116.	Projects less than $500K		3,100	856	4,930	3,555	
117.	Storage Plant sub total		26,865	27,003	23,772	18,605	
118.	Indirect Overheads		60,573	62,720	72,737	74,868	Excludes Technical Training Initiative
119.	Capitalized Administrative and General Overhead		24,369	24,199	30,404	30,742	
120.	Interest During Construction		5,183	3,790	4,249	5,541	
121.			90,125	90,709	107,390	111,151	
122.	Summary total		399,209	398,039	404,544	483,916	

COMPARISON OF CAPITAL EXPENDITURES
2007 BOARD APPROVED BUDGET,2008 THROUGH 2010 ACTUAL, 2011 ACTUAL, 2012 ESTIMATE, AND 2013 BUDGET
(EXPRESSED IN $MILLION)

Item No.		Col. 1 Board Approved Budget 2007	Col. 2 Actual 2008	Col. 3 Actual 2009	Col. 4 Actual 2010	Col. 5 Actual 2011	Col. 6 Estimate 2012	Col. 7 Budget 2013
A.	Customer Related							
1.1.1	Sales Mains **	76.5	60.6	48.2	46.7	72.1	47.2	61.9
1.1.2	Services	46.2	49.3	48.7	52.6	55.9	58.9	64.1
1.1.3	Meters and Regulation	11.5	9.7	11.9	8.3	7.6	12.7	12.6
1.1.4	Customer Related Distribution Plant	134.2	119.6	108.8	107.6	135.6	118.8	138.6
1.1.5	NGV Rental Equipment	0.2	0.3	0.2	0.2	-	0.3	0.3
1.1	TOTAL CUSTOMER RELATED CAPITAL	134.4	119.9	109.0	107.8	135.6	119.1	138.9
B.	System Improvements and Upgrades							
1.2.1	Mains - Relocations	7.7	14.8	8.0	13.2	15.5	20.0	23.4
1.2.2	- Replacement	58.1	58.8	49.9	55.7	54.6	23.5	49.1
1.2.3	- Reinforcement	26.6	16.7	16.8	14.0	9.8	62.4	111.6
1.2.4	Total Improvement Mains	92.4	90.3	74.7	82.9	79.8	105.9	184.1
1.2.5	Services - Relays	17.3	30.4	37.0	45.8	45.9	43.2	20.2
1.2.6	Regulators - Refits	3.5	3.5	7.7	6.4	5.6	5.4	6.8
1.2.7	Measurement and Regulation	15.7	13.4	9.2	10.3	11.4	17.6	25.7
1.2.8	Meters	20.2	18.9	15.9	13.1	17.8	16.1	20.7
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	149.1	156.5	144.5	158.5	160.5	188.2	257.5
C.	General and Other Plant							
1.3.1	Land, Structures and Improvements	3.1	3.4	2.9	14.0	20.9	22.8	19.0
1.3.2	Office Furniture and Equipment	0.7	1.0	0.9	1.9	5.1	1.3	3.9
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	7.7	11.0	11.4	6.5	7.4	4.2	4.7
1.3.4	Tools and Work Equipment	1.2	3.6	2.3	2.5	1.9	2.2	1.6
1.3.5	Computers and Communication Equipment	17.3	18.3	24.8	32.0	37.7	40.7	38.2
1.3	TOTAL GENERAL AND OTHER PLANT	30.0	37.3	42.3	56.9	73.0	71.2	67.4
D.	Underground Storage Plant	4.5	5.9	4.6	14.7	30.1	26.0	20.1
E.	Customer Information System (CIS)		46.4	48.7	(0.3)			
F.	TOTAL CAPITAL EXPENDITURES	318.0	366.0	349.1	337.6	399.2	404.5	483.9
G.	CUSTOMER ADDITIONS	46,228	41,052	32,089	36,902	35,657	37,927	38,896
**	Power Generation Projects Included in Sales Mains	18.0	13.0	5.7	4.6	19.8	1.6	14.0

Witnesses: L. Au
D. Kelly
R. Lei

LEAVE TO CONSTRUCT PROJECTS

1. As indicated in Exhibit B1, Tab 2, Schedule 1 and 2, Capital Expenditure Budget, Enbridge Gas Distribution Inc. ("Enbridge" or the("Company") is planning several construction projects which require the filing of a Leave to Construct ("LTC") application with the Ontario Energy Board (the "Board"). A summary is provided below. The projects that have a capital requirement in 2012 or 2013 include:
   - Alliston Reinforcement
   - Angus Reinforcement /c
   - Power Generation Project A[1] /c
   - Power Generation Project B[1]
   - Power Generation Project C[1]
   - Ottawa Reinforcement
   - Greater Toronto Area ("GTA") Reinforcement
   - Ottawa Innes Road Replacement

2. Alliston Reinforcement – Enbridge proposes to reinforce the Alliston area system with approximately 9 km of 8 inch diameter extra high pressure pipe from the Cookstown Gate Station to the vicinity of Highway 89 and Sideroad 10. The reinforcement allows Enbridge to meet the area growth and the pipeline is to be located entirely within the municipal road allowances. The estimated capital for this project is $5.4 million. An LTC application (EB-2011-0323) was filed on September 29, 2011. On January 23, 2012, the Board issued the Decision and Order approving the application. Construction is planned to start in the spring of 2012 with completion in the summer of the same year.

[1] Due to confidentiality, the customer is not identified.

Witnesses: E. Chin
N. MacNeil

3. Angus Reinforcement – Enbridge proposes to reinforce the vicinity of Angus with approximately 10 km of 8 inch diameter extra high pressure pipe from the Thornton Gate Station to the vicinity of Highway 89 and Sideroad 10. The Environmental Report is being prepared and the LTC application is expected to be filed in early 2012. Subject to Board approval, construction is planned to commence in the summer of 2012 for completion in the fall of 2012. While the route has not been finalized, the preliminary estimated total capital for this project is approximately $6 million.

4. Power Generation Project A - Enbridge has been asked to supply a proposed new gas fired cogeneration plant. The customer has submitted the proposal to the Ontario Power Authority (“OPA”)under the Combined Heat and Power (“CHP IV”) procurement program. If the proposal is accepted by the OPA, Enbridge will execute a service contract with the customer and file a LTC application with the Board in 2012. It is anticipated that approximately 2 km of 36 inch and approximately 3.5 km of 12 inch extra high pressure pipes are required for the project with a requested gas in-service date of Q2 2014.

5. Power Generation Project B - Enbridge has been asked to supply a proposed new gas fired cogeneration plant. The proponent has submitted the proposal to the OPA under the CHP IV procurement program. If the proposal is accepted by the OPA, Enbridge will execute a service contract with the proponent and file a LTC application with the Board in 2012. It is anticipated that approximately 12 km of 12 inch extra high pressure pipe is required for the project with a requested gas in-service date of Q1 2014.

6. Power Generation Project C - Enbridge has been asked to supply gas for a

potential generation project. Pending decision from the customer, Enbridge will execute a service contract and file a LTC application with the Board in 2012. It is anticipated that approximately 2 km of 12 inch extra high pressure and approximately 3.6 km of 12 inch high pressure pipes are required for the project with a requested gas in-service date of Q1 2014.

7. Preliminary estimated Enbridge capital cost for the three power generation projects, net of customer contributions, is approximately $15.5 million of which approximately $14 million is expected to be spent in 2013.

8. Ottawa Reinforcement - Enbridge proposes to reinforce the Ottawa system with approximately 20 km of 24 inch diameter extra high pressure pipe from the Richmond Gate Station to the vicinity of West Hunt Club Road and Greenbank Road. The reinforcement allows Enbridge to meet the area growth as well as pressure requirements at the Ottawa Gate Station. The Environmental Report is being prepared and the LTC application is expected to be filed in the spring of 2012. Subject to Board approval, construction is planned to commence in the spring of 2013 for completion in Q1 2014. While the route has not been finalized, the preliminary estimated total capital for this project is approximately $46 million. Approximately $30 million is the expected capital expenditure in 2013. About $1.9 million will be spent before 2013 and the balance in 2014.

9. GTA Reinforcement - Enbridge proposes to reinforce the GTA area with approximately 50 km of mostly 36 inch diameter extra high pressure pipe and an additional gate station. The reinforcement is required to allow Enbridge to meet area growth, and to increase supply diversity and reliability. The project will enhance network integrity, flexibility and the ability to dual-feed critical parts of the

GTA. Environmental and engineering work is at a very early stage and while much of the route is planned for utility corridors, final routes and costs cannot be determined without the benefit of the preliminary work. A very preliminary estimate of the total cost for the project is between $450 and $650 million. Preliminary planning and engineering are budgeted to cost $33 million in 2012/13 with $21million being the current estimated spend in 2013. It is anticipated that a LTC application will be filed in Q3 2012. Subject to Board approval, construction will take place in 2014 and 2015.

10. Ottawa Innes Road Replacement – Enbridge proposes to replace 3.0 km of Nominal Pipe Size (NPS) 8 inch pipe on Innes Road in Ottawa with an NPS 12 pipe. This replacement enables the mandated inspection of the pipeline. The retrofit of the existing NPS 8 pipe is impractical because of un-piggable configurations. In addition, the replacement will facilitate other improvements in the system. It is expected that a LTC will be filed in Q3 2012 with construction to be completed by Q4 2013. The preliminary estimated cost is $6 million, all of which is to be spent in 2013.

Witnesses: E. Chin
N. MacNeil

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ESTIMATE 2012 AND ACTUAL 2011

Item No.		Col. 1 Estimate 2012 ($Millions)	Col. 2 Actual 2011 ($Millions)	Col. 3 Estimate 2012 Over/(Under) Actual 2011 ($Millions)
A.	Customer Related			
1.1.1	Sales Mains	47.2	72.1	(24.9)
1.1.2	Services	58.9	55.9	3.0
1.1.3	Meters and Regulation	12.7	7.6	5.1
1.1.4	Customer Related Distribution Plant	118.8	135.6	(16.8)
1.1.5	NGV Rental Equipment	0.3	-	0.3
1.1	TOTAL CUSTOMER RELATED CAPITAL	119.1	135.6	(16.5)
B.	System Improvements and Upgrades			
1.2.1	Mains - Relocations	20.0	15.5	4.6
1.2.2	- Replacement	23.5	54.6	(31.1)
1.2.3	- Reinforcement	62.4	9.8	52.6
1.2.4	Total Improvement Mains	105.9	79.8	26.1
1.2.5	Service Relays	43.2	45.9	(2.7)
1.2.6	Regulator Refits	5.4	5.6	(0.2)
1.2.7	Measurement and Regulation	17.6	11.4	6.2
1.2.8	Meters	16.1	17.8	(1.7)
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	188.2	160.5	27.7
C.	General and Other Plant			
1.3.1	Land, Structures and Improvements	22.8	20.9	1.9
1.3.2	Office Furniture and Equipment	1.3	5.1	(3.8)
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	4.2	7.4	(3.2)
1.3.4	Tools and Work Equipment	2.2	1.9	0.3
1.3.5	Computers and Communication Equipment	40.7	37.7	3.0
1.3	TOTAL GENERAL AND OTHER PLANT	71.2	73.0	(1.8)
D.	Underground Storage Plant	26.0	30.1	(4.1)
E.	TOTAL CAPITAL EXPENDITURES	404.5	399.2	5.3

Witnesses: L. Au
D. Kelly
R. Lei

EXPLANATION OF MAJOR CHANGES
IN ESTIMATE 2012 UTILITY CAPITAL EXPENDITURES
FROM ACTUAL 2011 UTILITY CAPITAL EXPENDITURES

The 2012 Estimate is $404.5 million, which is $5.3 million or 1.3% over the 2011 Actual year of $399.2 million. Capital expenditure increases in the 2012 Estimate are primarily driven by system improvement and information technology requirements, partially offset by decreases in customer related and storage capital.

Item No.

1.1.4 Customer Related Distribution Plant - Decrease $16.8 Million

The decrease in customer related distribution plant is primarily driven by the power generation customers ($18.4 million). The York Energy Centre facility was completed in 2011 while several new facilities commence construction in 2012. The overall decrease was partially offset by an increased number of customer additions and higher indirect costs $1.6 million.

1.2.4 System Improvement Mains - Increase $26.1 Million

The increase is primarily due to the inclusion of several major reinforcement mains projects as well as additional safety and integrity initiatives. The reinforcement projects are required to support the expanded growth experienced and anticipated in the Toronto and York regions. The projects include GTA Reinforcement ($11.6 million), Angus Reinforcement ($6.0 million), Alliston Reinforcement ($3.9 million) and other projects ($4.2 million). The 2012 Estimate increase includes requirements for various relocation main projects ($4.5 million). These projects are mandated by other utilities and municipalities based on their needs. The safety and integrity initiatives represent programs which are required to maintain a safe and reliable distribution system. This would include amounts related to the integrity management initiatives

Witnesses: L. Au
D. Kelly
R. Lei

($10.9 million), Station B Relocation ($2.0 million), and Sheridan Gate Station relocation ($1.8 million). The overall increases were partially offset by the Cast Iron Replacement program ($18.8 million). The justification for all projects mentioned can be found at Exhibit B1, Tab 2, Schedule 2.

1.2.5 Service Relays – Decrease $2.7 Million

The decrease is primarily due to lower indirect costs.

1.2.7 Measurement and Regulation – Increase $6.2 Million

The increase is primarily due to station improvement requirements.

1.2.8 Meters - Decrease $1.7 Million

The decrease is primarily due to reduced requirements for meter replacements.

C. General and Other Plant - Decrease $1.8 Million

The decrease is driven by reduced requirements for office furniture and equipment ($3.8 million) and decreased requirements for Transportation and Heavy Work equipment ($3.2 million). This was partially offset by increased computer and communication equipment requirements ($3.0 million) which is primarily due to enhancements and necessary upgrades to existing hardware and software and increased requirements for Land, Structures and Improvements ($1.9 million). More details can be found at Exhibit B1, Tab 4, Schedule 1.

D. Underground Storage Plant - Decrease $4.1 Million

The decrease in Storage plant requirements reflects the completion of a major Pool Metering project in 2011. More information on Storage capital can be found at Exhibit B1, Tab 5, Schedule 1.

Witnesses: L. Au
D. Kelly
R. Lei

2012 CAPITAL EXPENDITURES BY PROJECT
(EXCEEDING $500,000)

Item No.	Description of Project	2012 Estimate ($000)	Historic 2011 Forecast ($000)	2011 Actual ($000)	2012 Over/ Under Actual ($000)
1.	Power Generation Projects A, B and C	1,460	-	-	1,460
2.	Ottawa Reinforcement Main	1,500	400	-	1,500
3.	GTA Reinforcement Main	11,627	1,850	1,441	10,186
4.	Technical Training Initiative	3,700	3,900	4,993	(1,293)
5.	Cast Iron Replacement Program	25,190	40,580	43,832	(18,642)
6.	Angus Reinforcement	6,000			6,000
7.	Low Pressure Delivery Meter Set Program	5,140			5,140
8.	Asset Risk Mitigation Initiative	5,700			5,700
9.	Alliston Reinforcement	4,660	800	532	4,128
10.	Relocation Main - Davis Drive	4,000			4,000
11.	Relocation Main - 9th Line (Markham Gate to Hoover Park)	3,000			3,000
12.	Records and GPS Strategy	3,000	-		3,000
13.	Torbram Relocation Main	2,488	1,646	1,696	792
14.	Kawartha Reinforcement- Phase 2 and 3	2,200	620	1,108	1,092
15.	Station B NPS 20	2,000			2,000
16.	Relocation Main- Bayly/Victoria	2,000			2,000
17.	Peterborough Reinforcement	1,900			1,900
18.	Sheridan Gate Station Bypass Relocation Main	1,824			1,824
19.	Revise Damage Prevention Standards and Processes	1,550			1,550
20.	Wyebridge Relocation Main	1,800			1,800
21.	Relocation Main- Teston Rd/Pine Valley	1,300			1,300
22.	Relocation Main - Highway 7(Bayview to Warden)	1,200			1,200
23.	Mayfield Road Reinforcement	1,000			1,000
24.	Relocation Main- Brock Road Phase 2	980			980
25.	Scarborough Reinforcement	751	659	(184)	935

Witnesses: L. Au
D. Kelly
R. Lei

2012 CAPITAL EXPENDITURES BY PROJECT
(EXCEEDING $500,000)

Item No.	Description of Project	2012 Estimate ($000)	Historic 2011 Forecast ($000)	2011 Actual ($000)	2012 Over/ Under Actual ($000)
26	Hurontario Reinforcement	750			750
27	Anne Street (Barrie) Relocation Main	750			750
28	High Street (Barrie) Relocation Main	600			600
29	Keele and McNaughton Reinforcement Main	560			560
30	Brampton Rapid Transit - Satellite & Orbitor Relocation Main	500			500
31	Technical Training and Operations Centre	13,000	18,000	16,197	(3,197)
32	Casselman Operations Centre Replacement	1,300			1,300
33	Pembroke Operations Centre Replacement	800			800
34	Kennedy Road Operations Centre Replacement	5,200			5,200
35	Leveraging SAP	4,900	6,017	3,389	1,511
36	Reporting Analytics for Finance & Customer Care Department	1,450	1,297	465	985
37	Desktop Replacement	1,200			1,200
38	Capman/O&M Management Program	1,500	556		1,500
39	Microsoft Enterprise Agreement	950	1,060	1,062	(112)
40	IT Request	650	676	770	(120)
41	Infrastructure Replacement:Nortel to CISCO	1,800	800	1,286	514
42	SRM Enhancements	750	1,222	1,065	(315)
43	Supply Chain Management	1,000	559	612	388
44	Enterprise GIS Implementation/Enhancement	500	1,949	2,264	(1,764)
45	Asset Record Data capture	500			500
46	Gas Molecule - 'nGARS	500	900	667	(167)
47	Enterprise Email/Records Management	1,400			1,400
48	EnMar Upgrade	700	1,061	1,197	(497)

Witnesses: L. Au
D. Kelly
R. Lei

2012 CAPITAL EXPENDITURES BY PROJECT
(EXCEEDING $500,000)

Item No.	Description of Project	2012 Estimate ($000)	Historic 2011 Forecast ($000)	2011 Actual ($000)	2012 Over/ Under Actual ($000)
49	Online Incident Management & Collaboration	500			500
50	EnVision Enhancements	4,800	1,688	3,003	1,797
51	Microsoft Program	2,200	1,545	1,122	1,078
52	GMS/Open Link - Customer web Access	900			900
53	Oracle Database upgrade	537			537
54	Tecumseh Office Facility	2,250			2,250
55	Certificate of Approval Air and Noise Emmissions	3,500	2,120	2,119	1,381
56	Purchase of Farm Properties	1,092	790	-	1,092
57	Pipeline Integrity Program	1,000			1,000
58	Plant Layout changes	750			750
59	Control Room Equipment changes	500			500
60	Observation Wells	5,000	1,650	1,091	3,909
61	Replace/Upgrade Storage Pool Metering	2,000	18,870	17,684	(15,684)
62	By-Pass of Sombra Station	1,000			1,000
63	KVT Upgrade K703	1,000	700	652	348
64	Mid Kimball/South Kimball Road Crossing	750			750

Witnesses: L. Au
D. Kelly
R. Lei

GROSS CUSTOMER ADDITIONS
AND AVERAGE COST PER CUSTOMER ADDITION
ESTIMATE 2012 AND ACTUAL 2011

		Col. 1	Col. 2	Col. 3
Item No.		Estimate 2012	Actual 2011	Estimate 2012 Over/(Under) Actual 2011
	RESIDENTIAL [1]			
1.1	New Construction	29,450	25,577	3,873
1.2	Replacement	5,948	7,722	(1,774)
1.	TOTAL RESIDENTIAL	35,398	33,299	2,099
2.1	COMMERCIAL [2]			
2.2	New Construction	1,727	1,709	18
2.	Replacement	798	641	157
	TOTAL COMMERCIAL	2,525	2,350	175
3.1	INDUSTRIAL			
3.2	New Construction	3	7	(4)
3.	Replacement	1	1	0
	TOTAL INDUSTRIAL	4	8	(4)
4.	TOTAL GROSS CUSTOMER ADDITIONS	37,927	35,657	2,270
5.	AVERAGE COSTS PER CUSTOMER ADDITION [3] INCLUDING POWER GENERATION	$3,132	$3,803	($671)
6.	AVERAGE COSTS PER CUSTOMER ADDITION [3] EXCLUDING POWER GENERATION	$3,088	$3,247	($159)

[1] Residential customers include singles homes and apartment ensuites
[2] Commercial customers include commercial and traditional apartment buildings
[3] Includes the cost of Sales Mains, New Services, Measurement and Regulation, and Meters

Witnesses: F. Ahmad
L. Au
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF GROSS CUSTOMER ADDITIONS
ESTIMATE 2012 AND ACTUAL 2011

Total Customer Additions

1. The total customer additions estimate for 2012 is 37,927, which is higher than the actual 2011 value by 2,270 customers. This increase has largely been driven by positive trends in the housing market and a continued economic recovery.

Average Cost Per Customer Addition

2. The primary factors that influence the average cost per customer addition are the mix of customer additions and service types (i.e., replacement versus new construction, residential versus commercial or industrial), the mix of meter types and the length of main required for the customer addition.

3. The 2012 Estimate average cost per customer addition is $671 lower than the 2011 Actual average cost primarily due to the completion of York Energy Centre power generation facility in 2011. The 2012 Estimate average cost per customer excluding power generation is $159, or 4.8% less than the 2011 Actual average cost primarily due to customer mix. Relative to 2011 Actual, the 2012 Estimate has fewer residential replacement customer additions.

Witnesses: F. Ahmad
L. Au
R. Lei

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ACTUAL 2011 AND BOARD APPROVED 2007

Item No.		Col. 1 Actual 2011 ($Millions)	Col. 2 Board Approved 2007 ($Millions)	Col. 3 Historic 2011 Over/(Under) Approved 2007 ($Millions)
A.	Customer Related			
1.1.1	Sales Mains	72.1	76.5	(4.4)
1.1.2	Services	55.9	46.2	9.7
1.1.3	Meters and Regulation	7.6	11.5	(3.9)
1.1.4	Customer Related Distribution Plant	135.6	134.2	1.4
1.1.5	NGV Rental Equipment	-	0.2	(0.2)
1.1	TOTAL CUSTOMER RELATED CAPITAL	135.6	134.4	1.2
B.	System Improvements and Upgrades			
1.2.1	Mains - Relocations	15.5	7.7	7.8
1.2.2	- Replacement	54.6	58.1	(3.5)
1.2.3	- Reinforcement	9.8	26.6	(16.8)
1.2.4	Total Improvement Mains	79.8	92.4	(12.6)
1.2.5	Services - Relays	45.9	17.3	28.6
1.2.6	Regulators - Refits	5.6	3.5	2.1
1.2.7	Measurement and Regulation	11.4	15.7	(4.3)
1.2.8	Meters	17.8	20.2	(2.4)
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	160.5	149.1	11.4
C.	General and Other Plant			
1.3.1	Land, Structures and Improvements	20.9	3.1	17.8
1.3.2	Office Furniture and Equipment	5.1	0.7	4.4
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	7.4	7.7	(0.3)
1.3.4	Tools and Work Equipment	1.9	1.2	0.7
1.3.5	Computers and Communication Equipment	37.7	17.3	20.4
1.3	TOTAL GENERAL AND OTHER PLANT	73.0	30.0	43.0
D.	Underground Storage Plant	30.1	4.5	25.6
E.	TOTAL CAPITAL EXPENDITURES	399.2	318.0	81.2

Witnesses: L. Au
D. Kelly
R. Lei

EXPLANATION OF MAJOR CHANGES
IN ACTUAL 2011 UTILITY CAPITAL EXPENDITURES
FROM BOARD APPROVED 2007 UTILITY CAPITAL EXPENDITURES

1. The 2011 Actual year is $399.5 million, which was $81.2 million or 25.5% above the 2007 Fiscal Board Approved Budget of $318.0 million. The Board in its EB-2006-0034 ADR settlement of 2007 capital expenditures allowed for a $300.0 million capital envelope, plus $18.0 million for the Portland Energy Centre. It was to be left to Company management to determine which projects it would pursue in 2007, except for the $18.0 million allocated to Portlands Energy Centre. The division of the $300.0 million capital amount in the ADR Settlement was created for internal purposes and was not specifically approved by the Board at the individual capital element level (i.e., services, regulators, meters).

2. The primary drivers of the increase in 2011 include the Technical Training and Operations Centre ($16.2 million), increased storage operation requirements ($25.6 million), increased requirements for information technology ($20.4 million), increased capital requirements for system improvements and upgrades ($11.4 million) ,other general plant increases ($6.4 million) and increased customer related capital ($1.2 million). Details and descriptions of the projects greater than $500,000 can be found at Exhibit B1, Tab 2, Schedule 2.

Witnesses: L. Au
D. Kelly
R. Lei

2011 CAPITAL EXPENDITURES BY PROJECT
(EXCEEDING $500,000)

Item No.	Description of Project	Historic 2011 Forecast ($000)	2011 Actual ($000)
1.	York Energy Centre Power Generation	20,029	20,049
2.	Everett Expansion Phase 1 Sales Main	1,113	1,376
3.	GTA Reinforcement	1,850	1,441
4.	Technical Training Initiative	3,900	4,993
5.	Cast Iron Replacement Program	40,580	43,832
6.	Alliston Reinforcement	800	532
7.	Torbram Relocation Main	1,646	1,696
8.	Kawartha Reinforcement- Phase 2 and 3	620	1,108
9.	Scarborough Reinforcement	659	(184)
10.	Ottawa Gate Station	-	1,660
11.	Anderson Road Replacement	2,287	2,291
12.	Keele and Finch Relocation Main	1,716	762
13.	Richmond Gate Reinforcement	897	1,655
14.	Hwy 35 South Relocation Main	1,083	852
15.	Hwy 93 Relocation Main	587	573
16.	County Rd 88 Relocation Main	525	525
17.	New Westminister Replacement Main	-	2,695
18.	Oshawa Gate Station	-	1,180
19.	Wasaga Beach Reinforcement	-	799
20.	Haley Gate Station	-	752
21.	Inline Inspection-Central region West	-	664
22.	Inline Inspection-Eastern region	-	662
23.	Woodbine Station Replacement	-	533
24.	York Region Rapid Transit/Hwy 7 Relocation Main	-	514
25.	Technical Training and Operations Centre	18,000	16,197
26.	Leveraging SAP	6,017	3,389

Witnesses: L. Au
D. Kelly
R. Lei

2011 CAPITAL EXPENDITURES BY PROJECT
(EXCEEDING $500,000)

Item No.	Description of Project	Historic 2011 Forecast ($000)	2011 Actual ($000)
27.	Reporting Analytics for Finance & Customer Care Department	1,297	465
28.	Capman/O&M Management Program	556	240
29.	Microsoft Enterprise Agreement	1,060	1,062
30.	IT Request	676	770
31.	Remedy Upgrade	1,100	913
32.	Infrastructure Replacement:Nortel to CISCO	800	1,286
33.	SRM Enhancements	1,222	1,065
34.	Supply Chain Management	559	612
35.	Enterprise GIS Implementation/Enhancement	1,949	2,264
36.	Gas Molecule - 'nGARS	900	667
37.	EnMar Upgrade	1,061	1,197
38.	EnVision Enhancements	1,688	3,003
39.	Microsoft Program	1,545	1,122
40.	CCSA (LBA Repatriation)	1,458	1,354
41.	Altra GMS Replacement	933	734
42.	Emissions Data Management & Reporting	677	703
43.	SRM Analytics	529	475
44.	Energy Supply Asset Transfer	-	745
45.	Integrated Training	-	531
46.	Certificate of Approval Air and Noise Emmissions	2,120	2,119
47.	Purchase of Farm Properties	790	-
48.	Phase II - Reservoir Simulation	-	512
49.	Replace/Upgrade Storage Pool Metering	18,870	17,684
50.	3D Seismic - Dow Moore/Coveny/Black Creek	2,017	1,707
51.	Observation Wells	1,650	1,091
52.	KVT Upgrade K703	700	652

Witnesses: L. Au
D. Kelly
R. Lei

GROSS CUSTOMER ADDITIONS
AND AVERAGE COST PER CUSTOMER ADDITION
ACTUAL 2011 AND BOARD APPROVED BUDGET 2011

Item No.		Col. 1 Actual 2011	Col. 2 Board Approved Budget 2011	Col. 3 Actual 2011 Over/(Under) Budget 2011
	RESIDENTIAL [1]			
1.1	New Construction	25,577	27,303	(1,726)
1.2	Replacement	7,722	6,309	1,413
1.	TOTAL RESIDENTIAL	33,299	33,612	(313)
2.1	COMMERCIAL [2]			
2.2	New Construction	1,709	1,792	(83)
2.	Replacement	641	829	(188)
	TOTAL COMMERCIAL	2,350	2,621	(271)
3.1	INDUSTRIAL			
3.2	New Construction	7	3	4
3.	Replacement	1	1	-
	TOTAL INDUSTRIAL	8	4	4
4.	TOTAL GROSS CUSTOMER ADDITIONS	35,657	36,237	(580)
5.	AVERAGE COSTS PER CUSTOMER ADDITION [3] INCLUDING POWER GENERATION	$3,803	$3,681 [4]	$ 122
6.	AVERAGE COSTS PER CUSTOMER ADDITION [3] EXCLUDING POWER GENERATION	$3,247	$3,129 [4]	$ 118

[1] Residential customers include singles homes and apartment ensuites
[2] Commercial customers include commercial and traditional apartment buildings
[3] Includes the cost of Sales Mains, New Services, Measurement and Regulation, and Meters
[4] Please note that there was no Board Approved Capital Budget for 2011

Witnesses: F. Ahmad
L. Au
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF GROSS CUSTOMER ADDITIONS
THE ACTUAL 2011 AND BOARD APPROVED BUDGET 2011

Total Customer Additions

1. The total customer additions for the actual 2011 are 35,657, which is 1.6%or 508 customers lower than the 2011 Board Approved budget of 36,237. This decrease was due to lower than expected customer growth in the residential new construction and commercial sectors. This unfavourable variance is driven by a weaker than expected economic recovery in Ontario.

Average Cost Per Customer Addition

2. There was no Board Approved Capital expenditure budget in 2011. Hence the change in average cost per customer is a function of the change in number of customer additions and customer mix. The average cost has increased because there are more residential replacement customer additions in the Actual year relative to the Board Approved Budget.

Witnesses: F. Ahmad
L. Au
R. Lei

SYSTEM EXPANSION MONITORING
2011 ACTUAL

		$millions	Reference Line on Page 3
	CAPITAL EXPENDITURE		
1	New Mains	44.62	1
2	Services	54.87	2
3	Meters and Regulation	6.86	3
4	Allowance for Marginal Overhead & Reinforcement	24.18	8
5	Total	**130.53**	9
	CASH FLOW		
6	Projected Annual Revenue from Capital Additions	25.06	16
7	Less: Operating Expenses	11.18	25
8	Operating Cash Flow before Income Taxes	13.88	
9	Income Tax before Allowance for Tax Shield from Interest and CCA	3.67	
10	Annual Operating Cash Flow after Income Taxes and before Allowance for Tax Shield due to Interest and CCA	**10.21**	
	PRESENT VALUE CALCULATION		
11	Present Value at the Beginning of Year one of Annual Cash Flows for the Revenue Horizon	144.98	
12	Present Value of Tax Shield from CCA	19.02	
13	Present Value of Total Cash Flows	164.00	
14	Present Value of Capital Investment	(130.42)	
15	**Net Present Value from Investment**	**33.58**	
16	**Profitability Index**	1.26	

Note: Columns may not add due to rounding.

Witnesses: F. Ahmad
P. Squires

CALCULATION OF REVENUE (DEFICIENCY)/SUFFICIENCY
2011 Actual

CAPITAL	Year 1 ($ Millions)	Year 2 ($ Millions)	Year 3 ($ Millions)	Year 4 ($ Millions)	Year 5 ($ Millions)
Beginning Balance (PPE)	-	128.110	122.337	116.565	110.792
Investments Made	130.530	-	-	-	-
Depreciation	2.420	5.772	5.772	5.772	5.772
Ending Balance (PPE)	128.110	122.337	116.565	110.792	105.020
Working Capital	(0.050)	(0.119)	(0.119)	(0.119)	(0.119)
Average Incremental Rate Base	64.01	125.10	119.33	113.56	107.79
REVENUE REQUIREMENT					
Rate of Return on Rate Base @ 6.50%	**4.158**	**8.129**	**7.753**	**7.378**	**7.003**
Add: **After Tax**					
Depreciation	2.420	5.772	5.772	5.772	5.772
Ontario and Federal Capital Tax	-	-	-	-	-
Expenses	1.568	2.769	2.769	2.769	2.769
Gas Costs	2.627	5.253	5.253	5.253	5.253
Less: CCA Tax shield	1.106	2.146	2.017	1.896	1.782
Interest tax shield	0.646	1.262	1.204	1.146	1.088
After tax revenue requirement	9.021	18.515	18.326	18.131	17.928
Income tax requirement	3.552	7.290	7.216	7.139	7.059
Revenue requirement	12.573	25.805	25.542	25.269	24.986
REVENUE (DEFICIENCY)/SUFFICIENCY					
Residential/Subdivision Revenue	17.669				
Small Commercial/Industrial Revenue	3.826				
Forecasted Revenue from Expansion	21.496	21.496	21.496	21.496	21.496
Effectiveness Factor	50%	100%	100%	100%	100%
Forecasted Effective Revenue From Expansion	10.748	21.496	21.496	21.496	21.496
Large Volume Revenue	0.001	2.674	3.563	3.563	3.563
Total Forecasted Effective Revenue From Expansion	10.748	24.170	25.059	25.059	25.059
Less:Revenue Requirement	12.573	25.805	25.542	25.269	24.986
Revenue (deficiency) / sufficiency	**(1.824)**	**(1.635)**	**(0.483)**	**(0.210)**	**0.073**

Witnesses: F. Ahmad
P. Squires

Derivation of Inputs to Return on System Expansion Monitoring: 2011 Actuals

($millions unless otherwise noted)	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9
Capital Expenditure		Exhibit Reference	Overheads	Adjustment see note 5				Total	Exhibit Reference B5 T2 S4 P1
1 Sales Mains	72.1	B1/2/4 pg 1	(34.9)	7.46				44.62	1
2 Services	55.9	B1/2/4 pg 1	(1.0)	-				54.87	2
3 Meters and Regulation	7.6	B1/2/4 pg 1	(0.8)	-				6.86	3
4 Sub-total								106.35	
5 Marginal A&G Overhead			2.5	-				2.53	
6 Normalized Mains Reinforcement			3.5	-				3.47	
7 Miscellaneous Regional Overhead			18.2	-				18.18	
8 Total Overhead								24.18	4
9 **TOTAL**								130.53	5
Cash Flow	Customer Additions	Exhibit Reference	Use/Customer	Revenue Rate				Total	
10 Projected Annual Revenues from Capital Additions			10^3 m^3	($) per 10^3 m^3 (per note 2)					
11 Residential - New Construction	25,577	B5/2/3 pg 1	2.433	219.27				13.6	
12 Residential - Replacement	7,722	B5/2/3 pg 1	2.334	223.24				4.0	
13 Commercial/Industrial - New Construction (excl. large volume customer	1,715	B5/2/3 pg 1	7.322	229.34				2.9	
14 Commercial/Industrial - Replacement	642	B5/2/3 pg 1	5.560	265.16				0.9	
15 Large Volume (see note 3)	1	B5/2/3 pg 1	3,264.000	1,089.50				3.6	
16 Projected Annual Revenues from Capital Additions								25.1	6
Operating Expenses	Customer Additions	Exhibit Reference	O&M/customer (per note 1) $	O&M Cost $	Use/Customer 10^3 m^3	Gas costs ($) per 10^3 m^3 (per note 2)	Gas Cost	Total	
17 Projected Annual Operating Costs									
18 Residential - New Construction	25,577	B5/2/3 pg 1	69.69	1.78	2.433	75.96	4.73	6.5	
19 Residential - Replacement	7,722	B5/2/3 pg 1	69.69	0.54	2.334	75.96	1.37	1.9	
20 Commercial/Industrial - New Construction	1,715	B5/2/3 pg 1	186.88	0.32	7.322	75.96	0.95	1.3	
21 Commercial/Industrial - Replacement	642	B5/2/3 pg 1	186.88	0.12	5.560	75.96	0.27	0.4	
22 Large Volume (see note 3)	1	B5/2/3 pg 1	320,820.19	0.321	3,264.000	0.00	0.00	0.3	
23 **Sub-total**								10.4	
24 Municipal Taxes (see note 4)								0.8	
25 **Total Operating Expenses**								11.2	7

Note 1 O&M costs are based on a weighted average per feasibility guidelines effective throughout calendar 2011.
Note 2 Revenue and gas costs are net of commodity. Gas cost are based on 2011 Board approved WACOG (Jan.2011-Dec.2011) except for Large Volume customized gas cost. Revenue is calculated based on Board approved rates for calendar 2011.
Note 3 This is Service Rate 125 Customer. Use per customer of 3,264.000 is the contract demand and the revenue is based on demand charge. The Gas Costs are not recovered through rates therefore they are not applicable.
Note 4 Municipal Taxes based on 0.60% of the total capital per portfolio per feasibility guidelines
Note 5 This adjustment referes to the capital net of contribution included in 2011 Investment Portfolio. The associated customer, York Energy Centre, has expected pipeline in service date December 1st 2011.

Witnesses: F. Ahmad
P. Squires

IMPACT OF EBO 188 SYSTEM EXPANSION ON EB-2009-0172
TYPICAL BILL IMPACTS BASED ON SALES SERVICE CUSTOMERS
2011 Historical

Item No.		Col.1 Residential / Subdivision	Col.2 Commercial / Industrial General Service	Col.3 Commercial / Industrial Large Volume	Col.4 TOTAL
1.	Deficiency Allocation ($ millions)	1.288	0.512	0.057	1.859
2.	Delivery Volumes (10^6m^3)	4,686.2	4,443.8	2,066.2	11,196.2
3.	Per Unit Rate ($ per m^3)	0.00027	0.00012	0.00003	n/a
4.	Typical Bill Volumes (m^3 /customer)	3,064	22,606	15,169,902 [1]	n/a
5.	Annual Bill Increase ($/customer)	0.84	2.61	418.67	n/a
6.	Annual Percent Increase (%)	0.07%	0.03%	0.007%	n/a

Notes:

[1] Typical bill volume for Large Volume customers is based on an average of volumes for gas rates 110-200

Witnesses: F. Ahmad
P. Squires

REVENUE FORECAST

1. The purpose of this evidence is to summarize the revenue forecast provided in this application. Overall, the 2013 Budget of Utility Operating Revenues represents a $203.2 million decrease compared to the 2012 Estimate.

2. A summary of the revenue forecast in the 2013 filing is provided in Table 1 below.

Table 1

Revenue Forecast
($ millions)

	Col. 1	Col. 2	Col. 3	Col. 4
	2011 Actual Year	2012 Estimate Bridge Year	2013 Budget Year	2007 Budget Board Approved
1.0 Gas Sales	1,978.4	2,158.8	2,004.1	2,377.1
2.0 Transportation of Gas	411.2	361.4	313.9	740.2
3.0 Transmission, Compression and Storage	1.5	1.7	1.7	1.7
4.0 Other Operating Revenue	41.4	40.1	39.0	35.1
5.0 Total Operating Revenue	2,432.5	2,562.0	2,358.7	3,154.1

3. The 2013 Budget is $2,358.7 million as shown at Exhibit C3, Tab 1, Schedule 1. This represents a $203.2 million decrease over the 2012 Bridge Year Estimate ("2012 Estimate") of $2,562.0 million. A comparison of the 2013 Budget of Utility Operating Revenues to the 2012 Estimate is provided at Exhibit C3, Tab 1, Schedule 2.

Witnesses: R. Lei
S. Qian

4. The 2012 Estimate is $2,562.0 million as shown at Exhibit C4, Tab 1 Schedule 1. This represents a $129.5 million increase over the 2011 Actual of $2,432.5 million. A comparison of the 2012 Estimate of Utility Operating Revenues to the 2011 Historical is provided at Exhibit C4, Tab 1, Schedule 2.

5. The 2012 Estimate represents a $592.1 million decrease over the 2007 Board Approved Budget of $3,154.1 million. A comparison of the 2012 Estimate of Utility Operating Revenues to the 2007 Board Approved Budget is provided at Exhibit C4, Tab 1, Schedule 3.

6. The 2011 Actual represents a $721.6 million decrease over the 2007 Board Approved Budget of $3,154.1 million. A comparison of the 2011 Actual of Utility Operating Revenues to the 2007 Board Approved Budget is provided at Exhibit C5, Tab 1, Schedule 2.

7. The year over year variances are further explained by the revenue categories in the following paragraphs.

<u>Gas Sales and Transportation of Gas Revenues</u>

8. Gas sales and transportation of gas revenues for the 2013 Budget were developed on the basis of EB-2012-0054 commodity rates (April 2012 QRAM) and the 2012 final rates that can be found in the Decision and Order for EB-2011-0277. A breakdown of the 2013 Budget gas sales and transportation of gas revenues by rate class is provided at Exhibit C3, Tab 2, Schedule 3.

9. The decrease in gas sales and transportation of gas revenues of $202.2 million from the 2012 Estimate to the 2013 Budget is primarily due to lower gas demand

forecast resulting from a forecast of warmer weather, lower commodity rates, continuing decline in average use for general service customers, partially offset by general service customer growth. Please refer to Exhibit C1, Tab 3, Schedule 2 for the details of the updated 2013 volume forecast. Also refer to Exhibit C3, Tab 2, Schedule 3 for a comparison of the 2013 Budget volume forecast to the 2012 Estimate. The forecast for weather is described in the degree day forecast found at Exhibit C2, Tab 3, Schedules 1 and 2.

10. The increase in gas sales and transportation of gas revenues of $130.5 million from the 2011 Actual to the 2012 Estimate is primarily due to general service customer growth, partially offset by a lower gas demand forecast resulting from a lower forecast of weather and the continued decline in average use for general service customers. The 2012 approved rates can be found in the Decision and Order for EB-2011-0277. Please refer to Exhibit C4, Tab 2, Schedule 3 for a comparison of the 2012 Estimate volume forecast to the 2011 Actual.

11. The decrease in gas sales and transportation of gas revenues of $ 727.7 million from the 2011 Actual to the 2007 Board Approved is primarily due to much lower PGVA reference price compared to the 2007, partially offset by customer growth. Please refer to Exhibit C5, Tab 1, Schedule 2 for a comparison of the 2011 Historical to the 2007 Board Approved.

<u>Transmission, Compression and Storage</u>

12. Transmission, Compression and Storage revenues have no significant variances from the 2013 Budget of $1.7 million compared to the 2012 Estimate and the 2011 Actual.

Witnesses: R. Lei
S. Qian

Other Operating Revenues

13. Other Operating Revenues for the 2013 Budget of the revenue items identified at Exhibit C3, Tab 3, Schedule 1 were developed based on the Company's approved final rates set out in the Decision and Order for EB-2011-0277.

14. The decrease in Other Operating Revenues of $1.1 million from the 2012 Estimate to the 2013 Budget is primarily due to lower Transactional Services revenues and lower late payment penalties, partially offset by higher miscellaneous revenues. A comparison of the 2013 Budget of Other Operating Revenues to the 2012 Estimate is provided at Exhibit C3, Tab 3, Schedule 1.

15. The decrease in Other Operating Revenues of $1.3 million from the 2011 Actual to the 2012 Estimate is primarily due to lower miscellaneous revenues primarily resulting from interest income, lower Service Charges and DPAC revenues. A comparison of the 2012 Estimate of Other Operating Revenues to the 2011 Historical is provided at Exhibit C4, Tab 3, Schedule 1.

16. The increase in other Operating Revenues of $6.3 million from the 2007 Board Approved to the 2011 Actual is primarily due to higher late payment penalties, higher service charges & DPAC, higher miscellaneous revenues, partially offset by lower NGV revenues. A comparison of the 2011 Actual Other Operating Revenues to the 2007 Board Approved is provided at Exhibit C5, Tab 3, Schedule 1.

17. Evidence on the NGV program is presented at Exhibit C3, Tab 5, Schedule 1, Exhibit C4, Tab 5, Schedule 1 and Exhibit C5, Tab 5, Schedule 1. Evidence on Transactional Services is presented at Exhibit C1, Tab 4, Schedule 1.

Witnesses: R. Lei
S. Qian

2013 GAS VOLUME BUDGET UPDATE

1. As a result of the availability of 2011 actual data that was filed in the Company's 2011 ESM application, docket EB-2012-0055 and the update of the forecast of degree days for 2013, the 2013 Test Year forecast of volumes and customers have been updated to 11 230.7 10^6m^3 and 2,020,962 customers respectively. The following summarizes the update of the volume forecast and average number of customers, and the detail of the 2013 Test Year volumes forecast are provided at Exhibit C3, Tab 2, Schedule 1, updated 2012-06-01.

2. The updated 2013 Test Year volumes reflect the meter reading heating degree days forecast for the Central Region of 3,481, a decrease of 51 degree days compared to the 2012 Estimate level of 3,532. The 2013 Budget volumes of 11 230.7 10^6m^3 are forecast to be 69.4 10^6m^3 or 0.6% below the 2012 Bridge Year Estimate of 11 300.1 10^6m^3. On a weather-normalized basis, the 2013 Budget volumes are forecast to be 7.2 10^6m^3 below the 2012 Bridge Year Estimate.

3. The updated 2013 Customers Budget of 2,020,962 is forecast to be 36,228 or 1.8% above the 2012 Bridge Year Estimate of 1,984,734. The increase in customers is primarily attributable to the customer additions estimate for 2013 of 38,579. The customer additions forecast underpins the new customer volumes of 104.3 10^6m^3 added between 2013 Budget and 2012 Bridge Year Estimate.

4. The updated 2013 large volume Test Year forecast volume has been updated to include the distribution volume of one large distributed energy plant of 117.8 10^6m^3. The updated 2013 large volume budget of 1 945.5 10^6m^3 is

expected to have an increase of 2.6 10^6m^3 in comparison to the 2012 Estimate of 1 943.4 10^6m^3 on a weather-normalized basis.

5. The 2013 Test Year general service volume of 9 285.2 10^6m^3 is lower by 9.8 10^6m^3 on a weather-normalized basis than the 2012 Bridge Year General Service volumes of 9,356.7 10^6m^3. The decrease is mainly due to lower average use per customer of 114.1 10^6m^3 offset primarily by customer growth. Detailed rate class explanations are shown at Exhibit C3, Tab 2, Schedule 3, updated 2012-06-01.

Witnesses: R. Lei
S. Qian

KEY ECONOMIC ASSUMPTIONS

ECONOMIC OUTLOOK: CANADA & U.S.

CALENDAR YEAR	2006	2007	2008	2009	2010	2011	2012F	2013F
REAL GDP (% CHANGE)								
CANADA	2.8	2.2	0.7	-2.8	3.2	2.5	2.1	2.4
U.S.	2.7	1.9	-0.3	-3.5	3.0	1.7	2.6	2.7
CANADA REAL EXPORTS (% CHANGE)	0.6	1.2	-4.7	-13.8	6.4	4.4	5.7	4.8
CANADA REAL IMPORTS (% CHANGE)	4.9	5.9	1.5	-13.4	13.1	6.5	3.6	3.9
CANADA HOUSING STARTS (000's)	227.4	228.3	211.1	149.1	189.9	194.0	197.2	192.8
CANADA UNEMPLOYMENT RATE (%)	6.3	6.0	6.1	8.3	8.0	7.6	7.4	7.1
CANADA EMPLOYMENT GROWTH (% CHANGE)	1.8	2.4	1.7	-1.6	1.4	1.6	0.9	1.3
CONSUMER PRICES (% CHANGE)								
CANADA	2.0	2.1	2.4	0.3	1.8	2.9	2.0	1.9
U.S.	3.2	2.9	3.8	-0.4	1.7	3.1	2.1	2.0

ECONOMIC OUTLOOK: ONTARIO

CALENDAR YEAR	2006	2007	2008	2009	2010	2011	2012F	2013F
REAL GDP (% CHANGE)	2.4	2.0	-0.7	-3.8	3.0	2.1	2.0	2.2
REAL MANUFACTURING OUTPUT (% CHANGE)	-2.1	-4.2	-8.9	-15.7	6.5	2.2	4.5	3.5
HOUSING STARTS (000's)	73.4	68.1	75.1	50.4	60.4	67.8	66.1	63.5
UNEMPLOYMENT RATE (%)	6.3	6.4	6.5	9.0	8.6	7.8	7.8	7.5
EMPLOYMENT GROWTH (% CHANGE)	1.2	1.8	1.5	-2.4	1.6	1.8	0.8	1.3
CONSUMER PRICES (% CHANGE)	1.8	1.8	2.3	0.4	2.4	3.1	1.8	1.7
RETAIL SALES (% CHANGE)	4.0	3.8	3.9	-2.5	5.4	3.0	3.6	3.8
WAGE RATE (% CHANGE)	5.7	6.0	5.8	6.5	5.3	3.1	3.9	5.3
REAL RESIDENTIAL NATURAL GAS PRICE (% CHANGE)	8.9	-11.4	1.5	-17.8	-13.2	-11.5	-11.2	16.2
REAL COMMERCIAL NATURAL GAS PRICE (% CHANGE)	10.0	-12.7	1.6	-19.8	-14.5	-12.8	-13.2	19.7

* The forecasts have been updated to reflect the Spring 2012 Economic Outlook.

Witnesses: H. Sayyan
M. Suarez

ECONOMIC OUTLOOK: REGIONS

CALENDAR YEAR	2006	2007	2008	2009	2010	2011	2012F	2013F
FRANCHISE HOUSING STARTS (000's)	46.4	43.8	50.8	32.7	38.8	47.9	40.8	41.0
GTA								
HOUSING STARTS (000's)	38.8	35.7	42.4	25.8	30.9	40.5	33.9	34.0
SINGLES	15.9	16.1	11.9	8.4	12.0	12.1	13.7	13.3
MULTIPLES	22.9	19.7	30.4	17.4	18.9	28.5	20.1	20.7
CONSUMER PRICES (% CHANGE)	1.6	1.9	2.4	0.5	2.5	3.0	1.8	1.7
UNEMPLOYMENT RATE (%)	6.3	6.5	6.6	9.0	9.1	8.2	7.9	7.8
EMPLOYMENT GROWTH (% CHANGE)	1.5	2.2	1.8	-1.7	2.1	2.1	1.1	2.2
COMMERCIAL VACANCY RATE (%)	7.3	6.3	5.4	6.9	7.9	7.0	7.0	7.0
INDUSTRIAL VACANCY RATE (%)	5.1	5.4	5.9	7.0	6.5	6.3	6.3	6.3
VINTAGE METRO REGION CENTRAL WEATHER ZONE (% CHANGE)	-1.1	-1.8	-0.9	-0.9	-1.1	-1.0	-1.0	-1.0
VINTAGE WESTERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-2.5	-2.7	-2.1	-2.1	-3.3	-2.9	-2.8	-2.7
VINTAGE CENTRAL REGION CENTRAL WEATHER ZONE (% CHANGE)	-3.8	-3.1	-2.7	-2.7	-2.9	-2.0	-1.8	-1.7
VINTAGE NORTHERN REGION CENTRAL WEATHER ZONE (% CHANGE)	-3.8	-3.6	-3.1	-3.1	-5.0	-3.8	-3.6	-3.5
CENTRAL HEATING DEGREE DAYS**	2635	2866	2919	2922	2659	2856	2655	2616
EASTERN								
HOUSING STARTS (000's)	6.1	6.8	7.2	6.0	6.6	6.0	5.7	5.8
SINGLES	2.7	3.1	3.1	2.6	2.4	2.2	2.5	2.5
MULTIPLES	3.4	3.6	4.1	3.4	4.2	3.8	3.2	3.3
CONSUMER PRICES (% CHANGE)	1.7	1.9	2.2	0.6	2.5	3.0	1.8	1.7
UNEMPLOYMENT RATE (%)	5.5	5.6	4.9	6.0	6.9	6.3	6.3	6.3
EMPLOYMENT GROWTH (% CHANGE)	3.2	2.0	4.0	-1.4	1.3	0.1	1.9	1.6
VINTAGE EASTERN WEATHER ZONE (% CHANGE)	-2.7	-2.8	-3.1	-3.1	-2.0	-2.6	-2.6	-2.6
EASTERN HEATING DEGREE DAYS	3210	3482	3458	3526	3092	3261	3372	3318
NIAGARA								
HOUSING STARTS (000's)	1.4	1.3	1.3	1.0	1.3	1.3	1.2	1.3
SINGLES	0.9	0.9	0.8	0.7	0.9	0.7	0.8	0.9
MULTIPLES	0.4	0.4	0.5	0.3	0.4	0.6	0.4	0.4
UNEMPLOYMENT RATE (%)	6.5	6.8	7.2	10.1	9.6	8.4	7.9	7.3
EMPLOYMENT GROWTH (% CHANGE)	-1.5	1.5	2.9	-6.0	1.8	2.5	1.5	1.9
VINTAGE NIAGARA WEATHER ZONE (% CHANGE)	-1.2	-1.1	-1.1	-1.1	-0.3	-0.9	-0.8	-0.8
NIAGARA HEATING DEGREE DAYS	2506	2700	2761	2821	2650	2737	2667	2690

* The forecasts have been updated to reflect the Spring 2012 Economic Outlook.
**Balance Point Heating Degree Days adjusted for billing cycles. The 2013 Degree Day forecast reflects the 2013 Updated Filing for Degree Days (Ex C2 T3 S2).

Witnesses: H. Sayyan
M. Suarez

AVERAGE USE FORECASTING MODEL

1. The purpose of this evidence is to present the forecasting methodology used to forecast average use for Rate 1 revenue class 20 and Rate 6 revenue classes 12, 48 and 73[1]. Rate 1 is the Company's residential rate class while Rate 6 is the Company's small apartment, commercial and industrial rate class. The forecasting methodology for the other revenue classes in Rate 1 and Rate 6 are very similar to the models presented in this exhibit.

2. In 2013[2] revenue class 20 is forecast to comprise 86% of Rate 1 volumes while /u revenue classes 12, 48 and 73 are forecast to collectively comprise 90% of Rate 6 volumes. Volumes for the remaining revenue classes in Rate 1 are forecast to comprise 14% of Rate 1 volumes while the remaining revenue classes in Rate 6 are /u forecast to comprise 10% of Rate 6 volumes.

3. For the 2001 budget the Company moved to a more objective forecasting methodology in order to address the Board's concern with the systematic bias attributed to the grassroots forecasting process. This forecasting methodology would remove systematic or subjective bias by developing regression models to forecast average use for the Company's Rate 1 general service customers and Rate 6 general service customers. The econometric methodology has been in place since 2001 and the forecasts produced and accepted in settlement proposals

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

Witnesses: H. Sayyan
M. Suarez

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

4. The year-over-year growth rates in average use for all revenue classes are used to compute the average use forecast for Rate 1 and Rate 6. Factors influencing overall average use include new customers (both new construction and replacement customers), the timing of new customer additions to the system, rate migration, gas prices, economic conditions and the Company's DSM programs. Refer to Exhibit C1, Tab 3, Schedule 1 for a summary of the Company's gas volume budget.

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

<u>Error Correction Model</u>

6. The Company uses the Error Correction Model ("ECM") to forecast the average use for Rate 1 and Rate 6. The Error Correction Model and the two step estimation procedure are described more fully in Engle and Granger (1987).[3] The ECM uses the concept of cointegration or long-run association between variables. In

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

other words, variables hypothesized to be linked by some theoretical economic relationship should not diverge from each other in the long run. Such variables may drift apart in the short run, however, if they were to diverge without bound, an equilibrium relationship among such variables could not be said to exist. The ECM methodology has been used extensively in the energy field for modeling electricity sales[4] and natural gas prices[5].

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

8. The estimated models are used to generate a normalized forecast of average use. The main purpose of the normalized forecast is to compute average use such that the weather impact has been taken out. Using the estimated coefficients, weather normalized average use data are obtained by replacing actual degree days in the model with budgeted degree days for 2013.

Average Use Forecasting Methodology

9. The model's specification is based on an objective criterion: to minimize both in-sample and out-of-sample forecast error. The discrepancy between actual average use and the model's forecast can be segregated into three major sources

[4] Engle, R.F., Granger, C.W.J. and Hallman, J.J. (1989), "Merging Short- and Long-Run Forecasts: An Application to Monthly Electricity Sales Forecasting," *Journal of Econometrics*, Vol.40.
[5] Bopp, A.E. (1990), "An Analytical Approach to Forecasting Natural Gas Prices," *AGA Forecasting Review*: American Gas Association.

of uncertainty: (1) model specification, (2) forecast error from the driver variables used in the model, and (3) unexpected shocks or structural breaks. Sources (2) and (3) are not within the Company's control and will inevitably occur regardless of which forecasting methodology is adopted. Therefore the objective of the modeling procedure, described below, is to minimize the controllable source of error, the model's specification.

10. The main criteria for assessing the model's predictive ability is the model's forecast accuracy. A comparison of actual un-normalized average use versus the forecasts produced by the model is used to assess predictive ability. Forecast accuracy is measured using both in-sample and out-of-sample Mean Percentage Error ("MPE") and RMSPE. In-sample, or ex-post, means that the estimated model incorporates the entire sample, in this case 1985 to 2010. Out-of-sample, or ex-ante, means that the model incorporates only a portion of the sample, in this case 1985 to 2007. Forecasts of average use are produced under both approaches and measured against actual average use from 2008 to 2010 quantitatively via MPE and RMSPE. A three year "hold out" sample is used to compute the out-of-sample forecast accuracy statistics since the forecasting horizon for budgeting purposes in this instance is three years. Table 1 presents the forecast accuracy statistics for Rate 1 and Rate 6. The smaller the MPE and RMSPE, the better model's forecast performance.

/u

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

Col 1.	Col 2.	Col 3.
Forecast Error Method	Rate 1	Rate 6
In-Sample % Variance (2 Years)	0.21%	-0.53%
In-Sample RMSPE (2 Years)	0.21%	0.80%
Out-of-Sample % Variance (2 Years)	1.71%	-2.48%
Out-of-Sample RMSPE (2 Years)	1.75%	2.67%

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

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

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

Witnesses: H. Sayyan
M. Suarez

TABLE 2

RATE 1 IN-SAMPLE FORECAST COMPARISON

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Fiscal Year	Actual Normalized Average Use Per Customer	Board Approved Normalized Average Use Per Customer[1,3]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer	Model's Normalized Average Use Per Customer[2]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer
	(m3)	m(3)	(2-3)	100*((2-3)/3)	(m3)	(2-6)	100*((2-6)/6)
2001	3,014	3,044	(30)	-1.0%	3,022	(8)	-0.26%
2002	2,980	2,970	10	0.3%	2,963	17	0.57%
2003	2,877	2,892	(15)	-0.5%	2,897	(20)	-0.69%
2004	2,843	n/a	n/a	n/a	2,864	(21)	-0.73%
2005	2,890	2,953	(63)	-2.1%	2,929	(39)	-1.33%
2006	2,796	2,850	(54)	-1.9%	2,816	(20)	-0.71%
2007	2,726	2,687	39	1.5%	2,695	31	1.15%
2008	2,636	2,647	(11)	-0.4%	2,611	25	0.97%
2009	2,616	2,637	(21)	-0.8%	2,623	(6)	-0.24%
2010	2,579	2,622	(43)	-1.6%	2,550	29	1.15%
2011	2,594	2643	(49)	-1.9%	2,607	(13)	-0.51%

/u

[1]Board approved normalized average use from RP-2000-0040, RP-2001-0032, RP-2002-0133, RP-2003-0203, EB-2005-000, EB-2006-0034, EB-2007-0615, EB-2008-0219, EB-2009-0172 and EB-2010-0146 for 2001, 2002, 2003, 2005, 2006, 2007, 2008, 2009, 2010 and 2011 respectively.

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

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

Witnesses: H. Sayyan
M. Suarez

TABLE 3
RATE 6 IN-SAMPLE FORECAST COMPARISON

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Fiscal Year	Actual Normalized Average Use Per Customer	Board Approved Normalized Average Use Per Customer[1,3]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer	Model's Normalized Average Use Per Customer[2]	Variance Normalized Average Use Per Customer	% Variance Normalized Average Use Per Customer
	(m3)	m(3)	(2-3)	100*((2-3)/3)	(m3)	(2-6)	100*((2-6)/6)
2001	22,510	22,643	(133)	-0.6%	22,706	(196)	-0.86%
2002	22,097	22,125	(28)	-0.1%	21,957	140	0.64%
2003	21,593	21,685	(92)	-0.4%	21,613	(20)	-0.09%
2004	21,472	n/a	n/a	n/a	21,377	95	0.44%
2005	22,241	22,507	(266)	-1.2%	22,334	(93)	-0.42%
2006	22,272	21,999	273	1.2%	22,149	123	0.55%
2007	22,783	21,010	1773	8.4%	22,973	(190)	-0.83%
2008	24,869	24,204	665	2.7%	25,273	(404)	-1.60%
2009	27,654	28,165	(512)	-1.8%	27,875	(222)	-0.79%
2010	29,106	27,949	1157	4.1%	29,691	(585)	-1.97%
2011	29,471	28,029	1442	5.1%	30,240	(769)	-2.54%

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[1]Board approved normalized average use from RP-2000-0040, RP-2001-0032, RP-2002-0133, RP-2003-0203, EB-2005-000, EB-2006-0034, EB-2007-0615, EB-2008-0219, EB-2009-0172 and EB-2010-0146 for 2001, 2002, 2003, 2005, 2006, 2007, 2008, 2009, 2010 and 2011 respectively.

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

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

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

Witnesses: H. Sayyan
M. Suarez

Breusch-Godfrey Serial Correlation LM Test[6]

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

Null Hypothesis: No serial correlation

Alternative Hypothesis: Serial correlation

ARCH Test

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

Null Hypothesis: No ARCH

Alternative Hypothesis: ARCH

Chow Forecast Test

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

Null Hypothesis: No structural change

Alternative Hypothesis: Structural change

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

Ramsey RESET Test

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

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

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

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

TABLE 4 - RATE 1 MODEL MNEMONICS

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

TABLE 5 - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Metro Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.48	6.60	0.00
LOG(CDD)	0.72	15.35	0.00
LOG(REALCRCRPG)	-0.03	-1.47	0.16
LOG(MET20VINT)	0.61	10.28	0.00
DUM2008	-0.06	-5.35	0.00
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.02		
F-statistic	333.86		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.33	0.74
DLOG(CDD)	0.76	25.87	0.00
DLOG(MET20VINT)	0.68	1.70	0.10
ECM_MET20(-1)	-0.32	-1.77	0.09
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	254.30		0.00

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.02	1.14	0.27
LOG(CDD)	0.72	19.14	0.00
LOG(REALCRCRPG)	-0.09	-5.41	0.00
LOG(WES20VINT)	0.26	5.10	0.00
LOG(CENTEMP)	0.16	1.63	0.12
DUM2008	-0.06	-6.65	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	395.67		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-2.34	0.03
DLOG(CDD)	0.72	36.22	0.00
DLOG(REALCRCRPG)	-0.08	-4.79	0.00
DUM2008	-0.02	-3.01	0.01
ECM_WES20(-1)	-0.69	-4.18	0.00
R-squared	0.99		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	360.88		0.00

Central Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.37	0.41	0.69
LOG(CDD)	0.72	16.52	0.00
LOG(REALCRCRPG)	-0.06	-3.11	0.01
LOG(CEN20VINT)	0.33	7.95	0.00
LOG(CENTEMP)	0.23	2.48	0.02
DUM2008	-0.07	-6.15	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	352.45		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.17	0.87
DLOG(CDD)	0.71	21.46	0.00
DLOG(REALCRCRPG)	-0.05	-1.83	0.08
DLOG(CEN20VINT)	0.24	1.55	0.14
DUM2008	-0.02	-2.02	0.06
ECM_CEN20(-1)	-0.79	-3.23	0.00
R-squared	0.96		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	107.94		0.00

Witnesses: H. Sayyan
M. Suarez

TABLE 5 CONTINUED - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Northern Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.98	1.12	0.28
LOG(CDD)	0.71	18.39	0.00
LOG(REALCRCRPG)	-0.10	-5.75	0.00
LOG(NOR20VINT)	0.26	7.42	0.00
LOG(CENTEMP)	0.18	1.92	0.07
DUM2009	-0.07	-6.31	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	544.00		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.06	0.95
DLOG(CDD)	0.70	21.04	0.00
DLOG(REALCRCRPG)	-0.05	-1.71	0.10
DLOG(NOR20VINT)	0.25	1.89	0.07
ECM_NOR20(-1)	-0.63	-2.38	0.03
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	0.02		
F-statistic	121.01		0.00

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.38	3.78	0.00
LOG(EDD)	0.81	18.18	0.00
LOG(REALERCRPG)	-0.04	-2.91	0.01
LOG(ERC20VINT)	0.24	15.87	0.00
DUM2008	-0.06	-6.32	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	534.83		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.77	0.01
DLOG(EDD)	0.79	23.91	0.00
DLOG(REALERCRPG)	-0.06	-2.18	0.04
DUM2008	-0.01	-1.82	0.08
ECM_ERC20(-1)	-0.68	-2.96	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	154.45		0.00

Niagara Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.33	4.53	0.00
LOG(NDD)	0.71	11.05	0.00
LOG(TIME)	-0.01	-0.91	0.37
LOG(REALNRCRPG)	-0.05	-1.47	0.16
LOG(NRC20VINT)	0.67	3.49	0.00
DUM2008	-0.09	-4.39	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	175.94		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.95	0.01
DLOG(NDD)	0.72	21.52	0.00
DLOG(REALNRCRPG)	-0.04	-1.53	0.14
DUM2008	-0.02	-1.73	0.10
ECM_NRC20(-1)	-0.56	-3.48	0.00
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	0.02		
F-statistic	129.85		0.00

Witnesses: H. Sayyan
M. Suarez

TABLE 6 - RATE 1

Model Diagnostic Tests

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Test		Metro Region	Western Region	Central Region	Northern Region	Eastern Weather Zone	Niagara Weather Zone
Breusch-Godfrey Serial Correlation LM Test	Test Statistic	0.01	0.70	0.39	0.45	1.37	0.26
	P Value	0.91	0.40	0.53	0.50	0.24	0.61
ARCH Test	Test Statistic	0.57	0.06	0.82	0.22	0.02	0.23
	P Value	0.45	0.80	0.36	0.64	0.89	0.63
Chow Forecast Test: Forecast from 2011 to 2011	Test Statistic	0.23	0.48	0.03	0.03	0.32	3.81
	P Value	0.64	0.50	0.86	0.85	0.58	0.07
Ramsey RESET Test	Test Statistic	2.60	0.69	0.77	0.43	1.09	0.00
	P Value	0.12	0.42	0.39	0.52	0.31	0.96

Witnesses: H. Sayyan
M. Suarez

TABLE 7 - RATE 6 MODEL MNEMONICS

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

Witnesses: H. Sayyan
M. Suarez

TABLE 8 - RATE 6 REVENUE CLASS 12 REGRESSION EQUATIONS

Central Revenue Class 12 (Apartment)

Single Equation Model

Variable	Coefficient	t-Statistic	p-Value
C	0.68	0.47	0.65
LOG(CDD)	0.68	6.64	0.00
LOG(REALCRCCPG)	-0.06	-1.16	0.26
LOG(CENTEMP)	0.67	5.29	0.00
DUM1996	-0.09	-4.95	0.00
DUMCRC12	0.23	5.49	0.00
AR(4)	-0.69	-2.83	0.01
R-squared	0.97		
Adjusted R-squared	0.95		
S.E. of regression	0.04		
F-statistic	75.790		0.00

Eastern Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	7.31	13.79	0.00
LOG(EDD)	0.45	6.89	0.00
LOG(TIME)	-0.03	-5.32	0.00
DUMERC12	0.32	27.06	0.00
DUM2011	-0.10	-3.41	0.00
LOG(REALERCCPG)	-0.03	-2.44	0.02
AR(1)	-0.48	-2.34	0.03
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	0.02		
F-statistic	74.27		0.00

Niagara Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	3.39	3.80	0.00
LOG(NDD)	0.64	11.05	0.00
LOG(TIME)	-0.03	-4.58	0.00
LOG(REALNRCCPG)	-0.07	-3.12	0.01
LOG(NIAGEMP)	0.43	3.89	0.00
DUMNRC12	-0.08	-8.54	0.00
AR(1)	-0.84	-4.61	0.00
R-squared	0.88		
Adjusted R-squared	0.84		
S.E. of regression	0.02		
F-statistic	23.18		0.00

Witnesses: H. Sayyan
M. Suarez

TABLE 8 CONTINUED - RATE 6 REVENUE CLASS 48 REGRESSION EQUATIONS

Central Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-0.01	0.99
LOG(CDD)	0.87	14.90	0.00
LOG(TIME)	-0.12	-8.92	0.00
LOG(CRCCOMVAC)	-0.07	-4.36	0.00
LOG(ONTGDP)	0.26	4.24	0.00
DUMCRC48	0.10	8.00	0.00
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.02		
F-statistic	130.94		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.18	0.86
DLOG(CDD)	0.86	29.44	0.00
DLOG(TIME)	-0.06	-3.36	0.00
DLOG(CRCCOMVAC)	-0.06	-4.69	0.00
DUMCRC48	0.03	3.69	0.00
ECM_CRC48(-1)	-0.83	-5.33	0.00
R-squared	0.98		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	176.19		0.00

Eastern Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.62	1.77	0.09
LOG(EDD)	0.75	10.76	0.00
LOG(TIME)	-0.16	-14.67	0.00
LOG(ONTGDP)	0.20	4.19	0.00
DUMERC48	0.10	5.75	0.00
DUM2010	0.14	6.56	0.00
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.02		
F-statistic	151.28		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.01	1.41	0.17
DLOG(EDD)	0.70	9.10	0.00
DLOG(TIME)	-0.13	-2.96	0.01
ECM_ERC48(-1)	-0.57	-1.66	0.11
R-squared	0.81		
Adjusted R-squared	0.79		
S.E. of regression	0.03		
F-statistic	31.60		0.00

Niagara Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-1.58	-0.97	0.34
LOG(NDD)	0.71	11.02	0.00
LOG(TIME)	-0.10	-4.81	0.00
LOG(REALNRCCPG)	-0.19	-4.52	0.00
LOG(ONTGDP)	0.44	3.89	0.00
DUMNRC48	0.11	4.56	0.00
DUM2010	-0.10	-3.34	0.00
R-squared	0.92		
Adjusted R-squared	0.89		
S.E. of regression	0.02		
F-statistic	37.80		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-1.77	0.09
DLOG(NDD)	0.75	10.93	0.00
DLOG(ONTGDP)	0.36	1.71	0.11
DUM2009	0.13	3.74	0.00
DUM2010	-0.14	-3.15	0.01
ECM_NRC48(-1)	-0.96	-2.65	0.02
AR(1)	-0.50	-1.58	0.13
R-squared	0.91		
Adjusted R-squared	0.88		
S.E. of regression	0.03		
F-statistic	30.86		0.00

Witnesses: H. Sayyan
M. Suarez

TABLE 8 CONTINUED - RATE 6 REVENUE CLASS 73 REGRESSION EQUATIONS

Central Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.93	0.55	0.59
LOG(CDD)	0.38	1.79	0.09
LOG(TIME)	-0.18	-2.89	0.01
LOG(ONTGDP)	0.50	2.31	0.03
DUMCRC73	0.45	8.99	0.00
AR(1)	0.15	0.63	0.54
R-squared	0.88		
Adjusted R-squared	0.85		
S.E. of regression	0.07		0.00
F-statistic	28.466		

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.02	-1.92	0.07
DLOG(CDD)	0.49	5.55	0.00
DLOG(ONTGDP)	0.62	1.88	0.07
DUMCRC73	0.24	5.30	0.00
DUM2009	-0.11	-2.29	0.03
ECM_CRC73(-1)	-0.43	-2.96	0.01
R-squared	0.81		
Adjusted R-squared	0.76		
S.E. of regression	0.04		
F-statistic	17.25		0.00

Eastern Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	76,867.32	1.37	0.19
EDD	8.47	0.55	0.59
DUM2003	89,980.16	5.01	0.00
DUM2004	-178,942.10	-9.88	0.00
DUMERC73	60,134.01	3.13	0.01
AR(1)	0.79	5.10	0.00
R-squared	0.88		
Adjusted R-squared	0.85		
S.E. of regression	19,310.69		
F-statistic	28.70		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2,136.94	0.37	0.71
D(EDD)	5.91	0.30	0.76
DUM2003	85,437.36	3.14	0.01
DUM2004	-265,415.30	-7.01	0.00
DUMERC73	32,925.96	2.19	0.04
ECM_ERC73(-1)	-0.50	-1.54	0.14
R-squared	0.78		
Adjusted R-squared	0.72		
S.E. of regression	25,721.67		
F-statistic	13.89		0.00

Niagara Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-8.87	-1.79	0.09
LOG(NDD)	0.63	1.92	0.07
LOG(TIME)	-0.21	-3.52	0.00
LOG(REALNRCCPG)	-0.22	-1.93	0.07
LOG(MANUFACTURING)	1.36	4.32	0.00
DUM2002	-0.38	-3.29	0.00
DUMNRC73	0.63	6.24	0.00
DUM2009	0.59	5.39	0.00
R-squared	0.93		
Adjusted R-squared	0.90		
S.E. of regression	0.11		
F-statistic	33.61		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.02	-0.83	0.42
DLOG(NDD)	0.71	2.67	0.02
DLOG(MANUFACTURING)	1.26	3.13	0.01
DUM2002	-0.23	-2.01	0.06
DUMNRC73	0.38	5.26	0.00
ECM_NRC73(-1)	-0.50	-1.84	0.08
DUM2010	-0.23	-2.38	0.03
AR(1)	-0.43	-1.88	0.08
R-squared	0.80		
Adjusted R-squared	0.72		
S.E. of regression	0.11		
F-statistic	9.95		0.00

Witnesses: H. Sayyan
M. Suarez

TABLE 9-RATE 6
Model Diagnostic Tests

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.	Col 9.	Col 10.	Col 11.
		Revenue Class 12 (Apartment) Model Diagnostic Tests			**Revenue Class 48 (Commercial) Model Diagnostic Tests**			**Revenue Class 73 (Industrial) Model Diagnostic Tests**		
Test		Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone	Central Weather Zone	Eastern Weather Zone	Niagara Weather Zone
Breusch-Godfrey Serial Correlation LM Test	Test Statistic	1.73	1.07	0.03	1.25	1.24	0.01	1.29	0.84	0.43
	P Value	0.19	0.30	0.86	0.26	0.27	0.92	0.26	0.36	0.51
ARCH Test	Test Statistic	0.01	0.44	0.48	0.22	0.11	2.60	1.46	0.10	0.33
	P Value	0.94	0.51	0.49	0.64	0.74	0.11	0.23	0.75	0.57
Chow Forecast Test: Forecast from 2011 to 2011	Test Statistic	2.46	11.62*	0.18	1.41	0.01	17.74	2.25	3.99	0.06
	P Value	0.14	0.00	0.67	0.25	0.91	0.00	0.15	0.06	0.81
Ramsey RESET Test	Test Statistic	2.12	0.43	4.02	0.24	0.99	0.52	2.31	1.27	0.87
	P Value	0.17	0.52	0.06	0.63	0.33	0.48	0.15	0.27	0.36

Witnesses: H. Sayyan
M. Suarez

14. Driver variable assumptions are presented in Table 10 in year over year growth rates. Major driver variables in the models are balance point heating degree days adjusted for billing cycles, vintage, time trend, real natural gas prices and economic variables. The driver variable assumptions are based on economic assumptions from the Economic Outlook, which can be found in Exhibit C2, Tab 3, Schedule 1.

15. Natural gas prices have an important impact on average use. Sharp increases typically have two effects. First, they influence customers' fuel use habits, for example, the lowering of thermostat settings. Second, price increases likely factor in customers' decision-making around the purchase of more efficient furnaces and other appliances. In addition, homeowners may also respond by retrofitting older residences in order to reduce energy consumption. In the models, real natural gas prices are used. The Consumer Price Index ("CPI") is used to convert nominal gas prices to real gas prices. Nominal energy price forecasts are based on the Fekete's Henry Hub price forecast produced in April 2011.

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

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

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

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

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

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

20. Calendar 1992 is used as the reference year for the vintage ratio since the Energy Efficiency Act prohibited selling of the conventional low-efficiency furnace in January 1992.[7] Consequently, this ratio will capture the increasing market share of both mid-efficiency and high-efficiency furnaces at the expense of declining market share of conventional furnaces over time. Table 10 shows that regions with stronger new construction additions, such as Western and Northern, experience a

[7] During the 1970s natural gas furnaces averages about 65% Annual Fuel Utilization Efficiency ("AFUE"). The Energy Efficiency Act imposed 78% AFUE as a minimum for gas furnaces manufactured after January 1, 1992.

sharper decline in the ratio than established regions like Metro. As more new customers are added to the revenue class the declining ratio leads to lower average use over time. Thus the sign of this variable's coefficient is positive.

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

<u>Risks to the Forecast</u>

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

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

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

25. Economic activity can impact both demand for appliances and natural gas. If the economy slows more significantly and natural gas prices are higher than indicated in the Economic Outlook (Exhibit C2, Tab 3, Schedule 1), average use will decline further.

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

Conclusion

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

Witnesses: H. Sayyan
M. Suarez

UPDATED 2013 BUDGET DEGREE DAYS

1. The purpose of this evidence is to provide an update to the forecast of degree days for 2013 that includes the latest actual data for 2011. Degree day evidence submitted on January 31, 2012 contained data up to the end of 2010 to generate the original 2013 forecast.

2. In its Decision with Reasons for EB-2006-0034 dated July 5, 2007, the Board stated that it "believes that given 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" (page 9). It also "accepted the analysis presented by the Company as part of its review of the nine comparable methodologies" and it decided to "accept the Company's … 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" (p. 10).

3. The Company used the same approach that underlies the Board-Approved methodology from the 2007 Test Year (EB-2006-0034) to update its 2013 forecasts for each of the weather zones. This process represents the evaluation of the same nine forecasting methods, forecasts of which were measured using accuracy statistics, and ranked based on how well each method met the criteria of accuracy, symmetry, and stability. Please see the description of the Degree Day Forecast Methodology and the review criteria as contained in paragraphs 3 to 8, EB-2011-0354, Exhibit C2, Tab 3, Schedule 1, page 3, filed January 31, 2012. The same process was carried out in this update.

Witnesses: H. Sayyan
M. Suarez

4. The updated analysis for the 2013 Test Year continues to support the use of the 20-Year Trend methodology for the Central Zone, the de Bever with Trend methodology for Eastern and the 10-Year Moving Average methodology for Niagara, as the most consistently accurate methodologies over time. While the forecast performance of the 10-Year Moving Average and the 50/50 Method have shown improvement in the Central zone since the 2007 Test Year, they do not show superior results over the 20-Year Trend method.

5. Applying the proposed methods result in the following 2013 degree days using actual degree day data to 2011:

Table 1
Summary of 2013 Proposed Degree Days & Methodology

	2013 Updated Filing Degree Day Methodology *Actuals to 2011*	**Environment Canada Degree Days**	**Gas Supply Degree Days**
Central	20-year Trend	3,512	3,481
Eastern	de Bever with Trend	4,334	4,297
Niagara	10-year Moving Average	3,480	3,420

6. For comparison, in the pre-filed 2013 evidence, the proposed methodologies with actual degree day data to 2010 provided:

Witnesses: H. Sayyan
M. Suarez

Table 2
Summary of 2013 Original Degree Days & Methodology

	2013 Original Filing Degree Day Methodology *Actuals to 2010*	**Environment Canada Degree Days**	**Gas Supply Degree Days**
Central	20-year Trend	3,536	3,513
Eastern	de Bever with Trend	4,344	4,307
Niagara	10-year Moving Average	3,458	3,403

Witnesses: H. Sayyan
M. Suarez

COMPARISON OF UTILITY OPERATING REVENUE
UPDATED 2013 BUDGET AND 2012 ESTIMATE

		Col. 1	Col. 2	Col. 3
Item No.		Updated 2013 Budget	2012 Estimate	2013 Budget Over/(Under) 2012 Estimate
		($Millions)	($Millions)	($Millions)
1.1	Gas Sales	2,004.1	2,158.8	(154.7)
1.2	Transportation of Gas	313.9	361.4	(47.5)
1.3	Transmission, Compression and Storage	1.7	1.7	-
1.4	Other Revenue	39.0	40.1	(1.1)
1.1	Total Operating Revenue	2,358.7	2,562.0	(203.3)

Witnesses: R. Lei
S. Qian

CUSTOMER METERS AND VOLUMES BY RATE CLASS
UPDATED 2013 BUDGET

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes ($10^6 m^3$)	Col. 3 Revenues ($Millions)	
General Service					
1.1.1	Rate 1 - Sales	1 590 583	3 962.5	1 281.5	
1.1.2	Rate 1 - T-Service	271 451	675.0	129.0	
1.1	Total Rate 1	1 862 034	4 637.5	1 410.5	
1.2.1	Rate 6 - Sales	132 728	2 712.5	672.2	
1.2.2	Rate 6 - T-Service	25 767	1 933.2	150.3	
1.2	Total Rate 6	158 495	4 645.7	822.5	
1.3.1	Rate 9 - Sales	8	1.8	0.5	
1.3.2	Rate 9 - T-Service	1	0.2	0.0	**
1.3	Total Rate 9	9	2.0	0.5	
1.	Total General Service Sales & T-Service	2 020 538	9 285.2	2 233.5	
Contract Sales					
2.1	Rate 100	0	0.0	0.0	
2.2	Rate 110	36	66.8	11.8	
2.3	Rate 115	2	2.8	0.5	
2.4	Rate 135	1	0.6	0.1	
2.5	Rate 145	13	24.8	4.2	
2.6	Rate 170	6	54.8	8.1	
2.7	Rate 200	1	163.1	23.7	
2.	Total Contract Sales	59	312.9	48.4	
Contract T-Service					
3.1	Rate 100	0	0.0	0.0	
3.2	Rate 110	165	420.8	13.1	
3.3	Rate 115	28	536.6	6.9	
3.4	Rate 125	5	0.0 *	10.9	
3.5	Rate 135	37	54.6	1.6	
3.6	Rate 145	95	128.0	3.3	
3.7	Rate 170	32	461.6	(0.6)	
3.8	Rate 300	3	31.0	0.2	
3.9	Rate 315	0	0.0	0.0	
3.	Total Contract T-Service	365	1 632.6	35.4	
4.	Total Contract Sales & T-Service	424	1 945.5	83.8	
5.	Total	2 020 962	11 230.7	2 317.3	

* There is no distribution volume for Rate 125 customers.
** Less than $50,000.

Witnesses: R. Lei
S. Qian

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
UPDATED 2013 BUDGET AND 2012 BRIDGE YEAR ESTIMATE

Item No.		Col. 1 Updated 2013 Budget	Col. 2 2012 Bridge Year Estimate	Col. 3 2013 Budget Over (Under) 2012 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 590 583	1 467 726	122 857
1.1.2	Rate 1 - T-Service	271 451	359 070	(87 619)
1.1	Total Rate 1	1 862 034	1 826 796	35 238
1.2.1	Rate 6 - Sales	132 728	127 809	4 919
1.2.2	Rate 6 - T-Service	25 767	29 691	(3 924)
1.2	Total Rate 6	158 495	157 500	995
1.3.1	Rate 9 - Sales	8	8	0
1.3.2	Rate 9 - T-Service	1	1	0
1.3	Total Rate 9	9	9	0
1.	Total General Service Sales & T-Service	2 020 538	1 984 305	36 233
Contract Sales				
2.1	Rate 100	0	0	0
2.2	Rate 110	36	34	2
2.3	Rate 115	2	0	2
2.4	Rate 135	1	1	0
2.5	Rate 145	13	11	2
2.6	Rate 170	6	5	1
2.7	Rate 200	1	1	0
2.	Total Contract Sales	59	52	7
Contract T-Service				
3.1	Rate 100	0	0	0
3.2	Rate 110	165	167	(2)
3.3	Rate 115	28	30	(2)
3.4	Rate 125	5	5	0
3.5	Rate 135	37	37	0
3.6	Rate 145	95	97	(2)
3.7	Rate 170	32	33	(1)
3.8	Rate 300	3	8	(5)
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	365	377	(12)
4.	Total Contract Sales & T-Service	424	429	(5)
5.	Total	2 020 962	1 984 734	36 228

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2013 BUDGET AND 2012 BRIDGE YEAR ESTIMATE
($10^6 m^3$)

Item No.		Col. 1 Updated 2013 Budget	Col. 2 2012 Bridge Year Estimate	Col. 3 2013 Budget Over (Under) 2012 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 962.5	3 693.2	269.3
1.1.2	Rate 1 - T-Service	675.0	890.1	(215.1)
1.1	Total Rate 1	4 637.5	4 583.3	54.2
1.2.1	Rate 6 - Sales	2 712.5	2 620.6	91.9
1.2.2	Rate 6 - T-Service	1 933.2	2 151.6	(218.4)
1.2	Total Rate 6	4 645.7	4 772.2	(126.5)
1.3.1	Rate 9 - Sales	1.8	1.0	0.8
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0
1.3	Total Rate 9	2.0	1.2	0.8
1.	Total General Service Sales & T-Service	9 285.2	9 356.7	(71.5)
Contract Sales				
2.1	Rate 100	0.0	0.0	0.0
2.2	Rate 110	66.8	64.3	2.5
2.3	Rate 115	2.8	0.0	2.8
2.4	Rate 135	0.6	0.6	0.0
2.5	Rate 145	24.8	21.4	3.4
2.6	Rate 170	54.8	49.7	5.1
2.7	Rate 200	163.1	162.2	0.9
2.	Total Contract Sales	312.9	298.2	14.7
Contract T-Service				
3.1	Rate 100	0.0	0.0	0.0
3.2	Rate 110	420.8	423.8	(3.0)
3.3	Rate 115	536.6	532.5	4.1
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	54.6	54.6	0.0
3.6	Rate 145	128.0	133.0	(5.0)
3.7	Rate 170	461.6	470.3	(8.7)
3.8	Rate 300	31.0	31.0	0.0
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 632.6	1 645.2	(12.6)
4.	Total Contract Sales & T-Service	1 945.5	1 943.4	2.1
5.	Total	11 230.7	11 300.1	(69.4)

* There is no distribution volume for Rate 125 customers.

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2013 BUDGET AND 2012 BRIDGE YEAR ESTIMATE
(10^6m^3)

Item No.		Col. 1 2013 Budget	Col. 2 2012 Bridge Year Estimate	Col. 3 2013 Budget Over (Under) 2012 Estimate (1-2)	Col. 4 2012* Adjustments		Col. 5 2013 Budget Over (Under) 2012 Estimate with Adjustments (3-4)
General Service							
1.1.1	Rate 1 - Sales	3 962.5	3 693.2	269.3	(26.9)		296.2
1.1.2	Rate 1 - T-Service	675.0	890.1	(215.1)	(6.0)		(209.1)
1.1	Total Rate 1	4 637.5	4 583.3	54.2	(32.9)		87.1
1.2.1	Rate 6 - Sales	2 712.5	2 620.6	91.9	(18.3)		110.2
1.2.2	Rate 6 - T-Service	1 933.2	2 151.6	(218.4)	(10.5)		(207.9)
1.2	Total Rate 6	4 645.7	4 772.2	(126.5)	(28.8)		(97.7)
1.3.1	Rate 9 - Sales	1.8	1.0	0.8	0.0		0.8
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0	0.0		0.0
1.3	Total Rate 9	2.0	1.2	0.8	0.0		0.8
1.	Total General Service Sales & T-Service	9 285.2	9 356.7	(71.5)	(61.7)		(9.8)
Contract Sales							
2.1	Rate 100	0.0	0.0	0.0	0.0		0.0
2.2	Rate 110	66.8	64.3	2.5	0.0	**	2.5
2.3	Rate 115	2.8	0.0	2.8	0.0		2.8
2.4	Rate 135	0.6	0.6	0.0	0.0		0.0
2.5	Rate 145	24.8	21.4	3.4	0.0	**	3.4
2.6	Rate 170	54.8	49.7	5.1	0.0	**	5.1
2.7	Rate 200	163.1	162.2	0.9	0.0		0.9
2.	Total Contract Sales	312.9	298.2	14.7	0.0		14.7
Contract T-Service							
3.1	Rate 100	0.0	0.0	0.0	0.0		0.0
3.2	Rate 110	420.8	423.8	(3.0)	(0.1)		(2.9)
3.3	Rate 115	536.6	532.5	4.1	0.0	**	4.1
3.4	Rate 125	0.0	0.0	0.0	0.0		0.0
3.5	Rate 135	54.6	54.6	0.0	0.0		0.0
3.6	Rate 145	128.0	133.0	(5.0)	(0.1)		(4.9)
3.7	Rate 170	461.6	470.3	(8.7)	(0.3)		(8.4)
3.8	Rate 300	31.0	31.0	0.0	0.0		0.0
3.9	Rate 315	0.0	0.0	0.0	0.0		0.0
3.	Total Contract T-Service	1 632.6	1 645.2	(12.6)	(0.5)		(12.1)
4.	Total Contract Sales & T-Service	1 945.5	1 943.4	2.1	(0.5)		2.6
5.	Total	11 230.7	11 300.1	(69.4)	(62.2)		(7.2)

*Note: Weather normalization adjustments have been made to the 2012 Bridge Year Estimate utilizing the 2013 Budget degree days in order to place the two years on a comparable basis.

** Less than 50,000 m^3.

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2013 BUDGET AND 2012 BRIDGE YEAR ESTIMATE
(10^6m^3)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
Item No.		2013 Budget	2012 Bridge Year Estimate	2013 Budget Over (Under) 2012 Estimate (1-2)	Change in Use	Weather	New Customers	Transfer Gains	Transfer Losses	Lost Customers	Added Load
General Service											
1.1.1	Rate 1 - Sales	3 962.5	3 693.2	269.3	(11.7)	(26.9)	89.1	218.8	0.0	0.0	0.0
1.1.2	Rate 1 - T-Service	675.0	890.1	(215.1)	9.7	(6.0)	0.0	0.0	(218.8)	0.0	0.0
1.1	Total Rate 1	4 637.5	4 583.3	54.2	(2.0)	(32.9)	89.1	218.8	(218.8)	0.0	0.0
1.2.1	Rate 6 - Sales	2 712.5	2 620.6	91.9	(26.6)	(18.3)	15.2	121.6	0.0	0.0	0.0
1.2.2	Rate 6 - T-Service	1 933.2	2 151.6	(218.4)	(86.3)	(10.5)	0.0	0.0	(121.6)	0.0	0.0
1.2	Total Rate 6	4 645.7	4 772.2	(126.5)	(112.9)	(28.8)	15.2	121.6	(121.6)	0.0	0.0
1.3.1	Rate 9 - Sales	1.8	1.0	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.3	Total Rate 9	2.0	1.2	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0
1.	Total General Service	9 285.2	9 356.7	(71.5)	(114.1)	(61.7)	104.3	340.4	(340.4)	0.0	0.0
Contract Sales											
2.1	Rate 100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.2	Rate 110	66.8	64.3	2.5	0.0	0.0 *	0.0	2.5	0.0	0.0	0.0
2.3	Rate 115	2.8	0.0	2.8	0.0	0.0	0.0	2.8	0.0	0.0	0.0
2.4	Rate 135	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.5	Rate 145	24.8	21.4	3.4	(0.1)	0.0 *	0.0	3.5	0.0	0.0	0.0
2.6	Rate 170	54.8	49.7	5.1	(0.4)	0.0 *	0.0	5.5	0.0	0.0	0.0
2.7	Rate 200	163.1	162.2	0.9	0.9	0.0	0.0	0.0	0.0	0.0	0.0
2.	Total Contract Sales	312.9	298.2	14.7	0.4	0.0	0.0	14.3	0.0	0.0	0.0
Contract T-Service											
3.1	Rate 100	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0
3.2	Rate 110	420.8	423.8	(3.0)	(0.4)	(0.1)	0.0	0.0	(2.5)	0.0	0.0
3.3	Rate 115	536.6	532.5	4.1	6.9	0.0 *	0.0	0.0	(2.8)	0.0	0.0
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	54.6	54.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.6	Rate 145	128.0	133.0	(5.0)	(1.4)	(0.1)	0.0	0.0	(3.5)	0.0	0.0
3.7	Rate 170	461.6	470.3	(8.7)	(2.9)	(0.3)	0.0	0.0	(5.5)	0.0	0.0
3.8	Rate 300	31.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 632.6	1 645.2	(12.6)	2.2	(0.5)	0.0	0.0	(14.3)	0.0	0.0
4.	Total Contract Sales & T-Service	1 945.5	1 943.4	2.1	2.6	(0.5)	0.0	14.3	(14.3)	0.0	0.0
5.	Total	11 230.7	11 300.1	(69.4)	(111.5)	(62.2)	104.3	354.7	(354.7)	0.0	0.0

* Less than 50,000 m^3.

Witnesses: R. Lei
S. Qian

The principal reasons for the variances contributing to the weather normalized decrease of 7.2 10^6m^3 in the 2013 Budget over the 2012 Estimate are as follows:

1. The volumetric increase of 87.1 10^6m^3 in Rate 1 is due to customer growth of 89.1 10^6m^3; partially offset by a lower average use per customer totaling 2.0 10^6m^3;

2. The volumetric decrease of 97.7 10^6m^3 in Rate 6 is due to a lower average use per customer totaling 112.9 10^6m^3; partially offset by a customer growth of 15.2 10^6m^3

3. The volumetric increase of 0.8 10^6m^3 in Rate 9 is due to a higher average use per station of 0.8 10^6m^3;

4. The volumetric increase for Contract Sales and T-Service of 2.6 10^6m^3 is due to increase in the commercial sector of 3.9 10^6m^3 and rate 200 of 0.9 10^6m^3; partially offset by the decrease in the industrial sector of 2.2 10^6m^3.

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
UPDATED 2013 BUDGET AND 2012 BRIDGE YEAR ESTIMATE
($ MILLIONS)

Item No.		Col. 1 Updated 2013 Budget	Col. 2 2012 Bridge Year Estimate	Col. 3 2013 Budget Over (Under) 2012 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 281.5	1 333.0	(51.5)
1.1.2	Rate 1 - T-Service	129.0	168.1	(39.1)
1.1	Total Rate 1	1 410.5	1 501.1	(90.6)
1.2.1	Rate 6 - Sales	672.2	751.7	(79.5)
1.2.2	Rate 6 - T-Service	150.3	164.1	(13.8)
1.2	Total Rate 6	822.5	915.8	(93.3)
1.3.1	Rate 9 - Sales	0.5	0.3	0.2
1.3.2	Rate 9 - T-Service	0.0	0.0	0.0
1.3	Total Rate 9	0.5	0.3	0.2
1.	Total General Service Sales & T-Service	2 233.5	2 417.2	(183.7)
Contract Sales				
2.1	Rate 100	0.0	0.0	0.0
2.2	Rate 110	11.8	13.9	(2.1)
2.3	Rate 115	0.5	0.0	0.5
2.4	Rate 135	0.1	0.1	0.0 *
2.5	Rate 145	4.2	4.5	(0.3)
2.6	Rate 170	8.1	9.4	(1.3)
2.7	Rate 200	23.7	28.5	(4.8)
2.	Total Contract Sales	48.4	56.4	(8.0)
Contract T-Service				
3.1	Rate 100	0.0	0.0	0.0
3.2	Rate 110	13.1	15.0	(1.9)
3.3	Rate 115	6.9	7.1	(0.2)
3.4	Rate 125	10.9	9.7	1.2
3.5	Rate 135	1.6	1.6	0.0 *
3.6	Rate 145	3.3	3.6	(0.3)
3.7	Rate 170	(0.6)	(0.8)	0.2
3.8	Rate 300	0.2	0.4	(0.2)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	35.4	36.6	(1.2)
4.	Total Contract Sales & T-Service	83.8	93.0	(9.2)
5.	Total	2 317.3	2 510.2	(192.9)

* Less than $50,000.

Witnesses: R. Lei
S. Qian

COMPARISON OF UTILITY OPERATING REVENUE
2012 ESTIMATE AND 2011 ACTUAL

Item No.		Col. 1 2012 Estimate Bridge Year ($Millions)	Col. 2 2011 Actual ($Millions)	Col. 3 2012 Estimate Over/(Under) 2011 Actual ($Millions)
1.1	Gas Sales	2,158.8	1,978.4	180.4
1.2	Transportation of Gas	361.4	411.2	(49.8)
1.3	Transmission, Compression and Storage	1.7	1.5	0.2
1.4	Other Revenue	40.1	41.4	(1.3)
1.1	Total Operating Revenue	2,562.0	2,432.5	129.5

Witnesses: R. Lei
S. Qian

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2012 BRIDGE YEAR ESTIMATE AND 2011 ACTUAL YEAR

Item No.		Col. 1 2012 Bridge Year Estimate	Col. 2 2011 Actual Year	Col. 3 2012 Estimate Over (Under) 2011 Historic (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 467 726	1 399 998	67 728
1.1.2	Rate 1 - T-Service	359 070	402 580	(43 510)
1.1	Total Rate 1	1 826 796	1 802 578	24 218
1.2.1	Rate 6 - Sales	127 809	121 783	6 026
1.2.2	Rate 6 - T-Service	29 691	35 540	(5849)
1.2	Total Rate 6	157 500	157 323	177
1.3.1	Rate 9 - Sales	8	10	(2)
1.3.2	Rate 9 - T-Service	1	1	0
1.3	Total Rate 9	9	11	(2)
1.	Total General Service Sales & T-Service	1 984 305	1 959 912	24 393
Contract Sales				
2.1	Rate 100	0	5	(5)
2.2	Rate 110	34	34	0
2.3	Rate 115	0	1	(1)
2.4	Rate 135	1	2	(1)
2.5	Rate 145	11	12	(1)
2.6	Rate 170	5	5	0
2.7	Rate 200	1	1	0
2.	Total Contract Sales	52	60	(8)
Contract T-Service				
3.1	Rate 100	0	10	(10)
3.2	Rate 110	167	171	(4)
3.3	Rate 115	30	27	3
3.4	Rate 125	5	4	1
3.5	Rate 135	37	40	(3)
3.6	Rate 145	97	114	(17)
3.7	Rate 170	33	32	1
3.8	Rate 300	8	8	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	377	406	(29)
4.	Total Contract Sales & T-Service	429	466	(37)
5.	Total	1 984 734	1 960 378	24 356

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2012 BRIDGE YEAR ESTIMATE AND 2011 ACTUAL YEAR
($10^6 m^3$)

Item No.		Col. 1 2012 Bridge Year Estimate	Col. 2 2011 Actual Year	Col. 3 2012 Estimate Over (Under) 2011 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 693.2	3 601.7	91.5
1.1.2	Rate 1 - T-Service	890.1	1 098.2	(208.1)
1.1	Total Rate 1	4 583.3	4 699.9	(116.6)
1.2.1	Rate 6 - Sales	2 620.6	2 323.2	297.4
1.2.2	Rate 6 - T-Service	2 151.6	2 396.8	(245.2)
1.2	Total Rate 6	4 772.2	4 720.0	52.2
1.3.1	Rate 9 - Sales	1.0	0.8	0.2
1.3.2	Rate 9 - T-Service	0.2	0.1	0.1
1.3	Total Rate 9	1.2	0.9	0.3
1.	Total General Service Sales & T-Service	9 356.7	9 420.8	(64.1)
Contract Sales				
2.1	Rate 100	0.0	2.3	(2.3)
2.2	Rate 110	64.3	66.6	(2.3)
2.3	Rate 115	0.0	0.1	(0.1)
2.4	Rate 135	0.6	1.4	(0.8)
2.5	Rate 145	21.4	22.8	(1.4)
2.6	Rate 170	49.7	48.5	1.2
2.7	Rate 200	162.2	168.7	(6.5)
2.	Total Contract Sales	298.2	310.4	(12.2)
Contract T-Service				
3.1	Rate 100	0.0	8.0	(8.0)
3.2	Rate 110	423.8	479.5	(55.7)
3.3	Rate 115	532.5	558.5	(26.0)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	54.6	60.0	(5.4)
3.6	Rate 145	133.0	161.5	(28.5)
3.7	Rate 170	470.3	474.1	(3.8)
3.8	Rate 300	31.0	30.5	0.5
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 645.2	1 772.1	(126.9)
4.	Total Contract Sales & T-Service	1 943.4	2 082.5	(139.1)
5.	Total	11 300.1	11 503.3	(203.2)

* There is no distribution volume for Rate 125 customers.

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2012 BRIDGE YEAR ESTIMATE AND 2011 ACTUAL YEAR
($10^6 m^3$)

Item No.		Col. 1 2012 Bridge Year Estimate	Col. 2 2011 Actual Year	Col. 3 2012 Estimate Over (Under) 2011 Actual (1-2)	Col. 4 2011* Adjustments	Col. 5 2012 Estimate Over (Under) 2011 Actual with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 693.2	3 601.7	91.5	(88.8)	180.3
1.1.2	Rate 1 - T-Service	890.1	1 098.2	(208.1)	(28.7)	(179.4)
1.1	Total Rate 1	4 583.3	4 699.9	(116.6)	(117.5)	0.9
1.2.1	Rate 6 - Sales	2 620.6	2 323.2	297.4	(61.6)	359.0
1.2.2	Rate 6 - T-Service	2 151.6	2 396.8	(245.2)	(39.9)	(205.3)
1.2	Total Rate 6	4 772.2	4 720.0	52.2	(101.5)	153.7
1.3.1	Rate 9 - Sales	1.0	0.8	0.2	0.0	0.2
1.3.2	Rate 9 - T-Service	0.2	0.1	0.1	0.0	0.1
1.3	Total Rate 9	1.2	0.9	0.3	0.0	0.3
1.	Total General Service Sales & T-Service	9 356.7	9 420.8	(64.1)	(219.0)	154.9
Contract Sales						
2.1	Rate 100	0.0	2.3	(2.3)	0.0 **	(2.3)
2.2	Rate 110	64.3	66.6	(2.3)	0.0 **	(2.3)
2.3	Rate 115	0.0	0.1	(0.1)	0.0	(0.1)
2.4	Rate 135	0.6	1.4	(0.8)	0.0	(0.8)
2.5	Rate 145	21.4	22.8	(1.4)	0.1	(1.5)
2.6	Rate 170	49.7	48.5	1.2	0.0 **	1.2
2.7	Rate 200	162.2	168.7	(6.5)	(1.9)	(4.6)
2.	Total Contract Sales	298.2	310.4	(12.2)	(1.8)	(10.4)
Contract T-Service						
3.1	Rate 100	0.0	8.0	(8.0)	(0.1)	(7.9)
3.2	Rate 110	423.8	479.5	(55.7)	(0.4)	(55.3)
3.3	Rate 115	532.5	558.5	(26.0)	0.1	(26.1)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	54.6	60.0	(5.4)	0.0	(5.4)
3.6	Rate 145	133.0	161.5	(28.5)	(1.0)	(27.5)
3.7	Rate 170	470.3	474.1	(3.8)	(1.6)	(2.2)
3.8	Rate 300	31.0	30.5	0.5	0.0	0.5
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 645.2	1 772.1	(126.9)	(3.0)	(123.9)
4.	Total Contract Sales & T-Service	1 943.4	2 082.5	(139.1)	(4.8)	(134.3)
5.	Total	11 300.1	11 503.3	(203.2)	(223.8)	20.6

*Note: Weather normalization adjustments have been made to the 2011 Historical Year utilizing the 2012 Budget degree days in order to place the two years on a comparable basis.

** Less than 50,000 m³.

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2012 BRIDGE YEAR ESTIMATE AND 2011 ACTUAL YEAR
(10^6m^3)

Item No.		Col. 1 2012 Bridge Year Estimate	Col. 2 2011 Actual Year	Col. 3 2012 Estimate Over (Under) 2011 Actual (1-2)	Col. 4 Change in Use	Col. 5 Weather	Col. 6 New Customers	Col. 7 Transfer Gains	Col. 8 Transfer Losses	Col. 9 Lost Customers	Col. 10 Added Load
General Service											
1.1.1	Rate 1 - Sales	3 693.2	3 601.7	91.5	(15.2)	(88.8)	59.0	136.5	0.0	0.0	0.0
1.1.2	Rate 1 - T-Service	890.1	1 098.2	(208.1)	(42.9)	(28.7)	0.0	0.0	(136.5)	0.0	0.0
1.1	Total Rate 1	4 583.3	4 699.9	(116.6)	(58.1)	(117.5)	59.0	136.5	(136.5)	0.0	0.0
1.2.1	Rate 6 - Sales	2 620.6	2 323.2	297.4	178.0	(61.6)	13.2	168.7	(0.9)	0.0	0.0
1.2.2	Rate 6 - T-Service	2 151.6	2 396.8	(245.2)	(68.9)	(39.9)	0.0	28.5	(164.9)	0.0	0.0
1.2	Total Rate 6	4 772.2	4 720.0	52.2	109.1	(101.5)	13.2	197.2	(165.8)	0.0	0.0
1.3.1	Rate 9 - Sales	1.0	0.8	0.2	0.4	0.0	0.0	0.0	0.0	(0.2)	0.0
1.3.2	Rate 9 - T-Service	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
1.3	Total Rate 9	1.2	0.9	0.3	0.5	0.0	0.0	0.0	0.0	(0.2)	0.0
1.	Total General Service	9 356.7	9 420.8	(64.1)	51.5	(219.0)	72.2	333.7	(302.3)	(0.2)	0.0
Contract Sales											
2.1	Rate 100	0.0	2.3	(2.3)	0.0	0.0 *	0.0	0.0	(2.3)	0.0	0.0
2.2	Rate 110	64.3	66.6	(2.3)	(2.9)	0.0 *	0.0	0.9	(0.2)	(0.1)	0.0
2.3	Rate 115	0.0	0.1	(0.1)	(1.9)	0.0	0.0	1.8	0.0	0.0	0.0
2.4	Rate 135	0.6	1.4	(0.8)	(0.8)	0.0	0.0	0.0	0.0	0.0	0.0
2.5	Rate 145	21.4	22.8	(1.4)	(0.2)	0.1	0.0	0.0	(1.3)	0.0	0.0
2.6	Rate 170	49.7	48.5	1.2	1.2	0.0 *	0.0	0.0	0.0	0.0	0.0
2.7	Rate 200	162.2	168.7	(6.5)	(4.6)	(1.9)	0.0	0.0	0.0	0.0	0.0
2.	Total Contract Sales	298.2	310.4	(12.2)	(9.2)	(1.8)	0.0	2.7	(3.8)	(0.1)	0.0
Contract T-Service											
3.1	Rate 100	0.0	8.0	(8.0)	0.0	(0.1)	0.0	0.0	(7.9)	0.0	0.0
3.2	Rate 110	423.8	479.5	(55.7)	(19.4)	(0.4)	0.0	21.8	(57.2)	(0.5)	0.0
3.3	Rate 115	532.5	558.5	(26.0)	(59.5)	0.1	0.0	49.3	(15.9)	0.0	0.0
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	54.6	60.0	(5.4)	(5.4)	0.0	0.0	0.0	0.0	0.0	0.0
3.6	Rate 145	133.0	161.5	(28.5)	(6.4)	(1.0)	0.0	0.0	(20.5)	(0.6)	0.0
3.7	Rate 170	470.3	474.1	(3.8)	(4.8)	(1.6)	0.0	4.9	(2.3)	0.0	0.0
3.8	Rate 300	31.0	30.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 645.2	1 772.1	(126.9)	(95.0)	(3.0)	0.0	76.0	(103.8)	(1.1)	0.0
4.	Total Contract Sales & T-Service	1 943.4	2 082.5	(139.1)	(104.2)	(4.8)	0.0	78.7	(107.6)	(1.2)	0.0
5.	Total	11 300.1	11 503.3	(203.2)	(52.7)	(223.8)	72.2	412.4	(409.9)	(1.4)	0.0

* Less than 50,000 m^3.

Witnesses: R. Lei
S. Qian

The principal reasons for the variances contributing to the weather normalized increase of 20.6 10^6m^3 in the 2012 Bridge Year Estimate over the 2011 Actual Year are as follows:

1. The volumetric increase of 0.9 10^6m^3 in Rate 1 is due to customer growth of 59.0 10^6m^3; partially offset by a lower average use per customer totaling 58.1 10^6m^3;

2. The volumetric increase of 153.7 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 31.4 10^6m^3, a customer growth of 13.2 10^6m^3, and a higher average use per customer totaling 109.1 10^6m^3;

3. The volumetric increase of 0.3 10^6m^3 in Rate 9 is due to a higher average use per station of 0.5 10^6m^3; partially offset by the loss of stations of 0.2 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 134.3 10^6m^3 is due to decreases in the apartment sector of 21.5 10^6m^3, the industrial sector of 139.7 10^6m^3, and of Rate 200 of 4.6 10^6m^3; partially offset by the increase of the commercial sector of 31.5 10^6m^3.

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2012 BRIDGE YEAR ESTIMATE AND 2011 ACTUAL YEAR
($ MILLIONS)

Item No.		Col. 1 2012 Bridge Year Estimate	Col. 2 2011 Actual Year	Col. 3 2012 Estimate Over (Under) 2011 Actual (1-2)
General Service				
1.1.1	Rate 1 - Sales	1 333.0	1 264.0	69.0
1.1.2	Rate 1 - T-Service	168.1	194.9	(26.8)
1.1	Total Rate 1	1 501.1	1 458.9	42.2
1.2.1	Rate 6 - Sales	751.7	675.2	76.5
1.2.2	Rate 6 - T-Service	164.1	178.2	(14.1)
1.2	Total Rate 6	915.8	853.4	62.4
1.3.1	Rate 9 - Sales	0.3	0.2	0.1
1.3.2	Rate 9 - T-Service	0.0	0.0	0.0
1.3	Total Rate 9	0.3	0.2	0.1
1.	Total General Service Sales & T-Service	2 417.2	2 312.5	104.7
Contract Sales				
2.1	Rate 100	0.0	0.6	(0.6)
2.2	Rate 110	13.9	14.1	(0.2)
2.3	Rate 115	0.0	0.0	0.0
2.4	Rate 135	0.1	0.3	(0.2)
2.5	Rate 145	4.5	4.5	0.0
2.6	Rate 170	9.4	9.4	0.0
2.7	Rate 200	28.5	28.3	0.2
2.	Total Contract Sales	56.4	57.2	(0.8)
Contract T-Service				
3.1	Rate 100	0.0	0.5	(0.5)
3.2	Rate 110	15.0	13.8	1.2
3.3	Rate 115	7.1	7.7	(0.6)
3.4	Rate 125	9.7	7.8	1.9
3.5	Rate 135	1.6	2.2	(0.6)
3.6	Rate 145	3.6	5.4	(1.8)
3.7	Rate 170	(0.8)	5.0	(5.8)
3.8	Rate 300	0.4	0.5	(0.1)
3.9	Rate 315	0.0	0.4	(0.4)
3.	Total Contract T-Service	36.6	43.3	(6.7)
4.	Total Contract Sales & T-Service	93.0	100.5	(7.5)
5.	Total	2 510.2	2 413.0	97.2

Witnesses: R. Lei
S. Qian

DETAILS OF OTHER REVENUE
2012 BRIDGE YEAR AND 2011 ACTUAL YEAR

		Col. 1	Col. 2	Col. 3
Item No.		2012 Bridge Year ($Millions)	2011 Actualal Year ($Millions)	2012 Bridge Over/(Under) 2011 Actualal ($Millions)
1.1	Service Charges & DPAC	12.7	13.2	(0.5)
1.2	Rental Revenue - NGV Program	0.4	0.5	(0.1)
1.3	Late Payment Penalties	13.2	13.2	-
1.4	Dow Moore Recovery	0.3	0.3	-
1.5	Transactional Services (net)	8.0	8.0	-
1.6	Miscellaneous	0.1	0.8	(0.7)
1.7	Open Bill Revenue	5.4	5.4	-
1.9	Total Other Revenue	40.1	41.4	(1.3)

Witnesses: R. Lei
S. Qian

COMPARISON OF UTILITY OPERATING REVENUE
2011 ACTUAL AND BOARD APPROVED 2007 BUDGET

Item No.		Col. 1 2011 Actual ($Millions)	Col. 2 Board Approved 2007 Budget ($Millions)	Col. 3 2011 Actual Over/(Under) OEB Approved 2007 Budget ($Millions)
1.1	Gas Sales	1,978.4	2,377.1	(398.7)
1.2	Transportation of Gas	411.2	740.2	(329.0)
1.3	Transmission, Compression and Storage	1.5	1.7	(0.2)
1.4	Other Revenue	41.4	35.1	6.3
1.1	Total Operating Revenue	2,432.5	3,154.1	(721.6)

Witnesses: R. Lei
S. Qian

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2011 ACTUAL YEAR

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	Col. 3 Revenues ($Millions)	
General Service					
1.1.1	Rate 1 - Sales	1 399 998	3 601.7	1 264.0	
1.1.2	Rate 1 - T-Service	402 580	1 098.2	194.9	
1.1	Total Rate 1	1 802 578	4 699.9	1 458.9	
1.2.1	Rate 6 - Sales	121 783	2 323.2	675.2	
1.2.2	Rate 6 - T-Service	35 540	2 396.8	178.2	
1.2	Total Rate 6	157 323	4 720.0	853.4	
1.3.1	Rate 9 - Sales	10	0.8	0.2	
1.3.2	Rate 9 - T-Service	1	0.1	0.0	**
1.3	Total Rate 9	11	0.9	0.2	
1.	Total General Service Sales & T-Service	1 959 912	9 420.8	2 312.5	
Contract Sales					
2.1	Rate 100	5	2.3	0.6	
2.2	Rate 110	34	66.6	14.1	
2.3	Rate 115	1	0.1	0.0	**
2.4	Rate 135	2	1.4	0.3	
2.5	Rate 145	12	22.8	4.5	
2.6	Rate 170	5	48.5	9.4	
2.7	Rate 200	1	168.7	28.3	
2.	Total Contract Sales	60	310.4	57.2	
Contract T-Service					
3.1	Rate 100	10	8.0	0.5	
3.2	Rate 110	171	479.5	13.8	
3.3	Rate 115	27	558.5	7.7	
3.4	Rate 125	4	0.0 *	7.8	
3.5	Rate 135	40	60.0	2.2	
3.6	Rate 145	114	161.5	5.4	
3.7	Rate 170	32	474.1	5.0	
3.8	Rate 300	8	30.5	0.5	
3.9	Rate 315	0	0.0	0.4	
3.	Total Contract T-Service	406	1 772.1	43.3	
4.	Total Contract Sales & T-Service	466	2 082.5	100.5	
5.	Total	1 960 378	11 503.3	2 413.0	

* There is no distribution volume for Rate 125 customers.
** Less than $50,000.

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 ACTUAL YEAR AND 2010 HISTORIC YEAR
(10^6m^3)

Item No.		Col. 1 2011 Actual Year	Col. 2 2010 Historic Year	Col. 3 2011 Actual Over (Under) 2010 Historic (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 601.7	3 119.2	482.5
1.1.2	Rate 1 - T-Service	1 098.2	1 294.7	(196.5)
1.1	Total Rate 1	4 699.9	4 413.9	286.0
1.2.1	Rate 6 - Sales	2 323.2	1 959.3	363.9
1.2.2	Rate 6 - T-Service	2 396.8	2 382.7	14.1
1.2	Total Rate 6	4 720.0	4 342.0	378.0
1.3.1	Rate 9 - Sales	0.8	1.0	(0.2)
1.3.2	Rate 9 - T-Service	0.1	0.1	0.0
1.3	Total Rate 9	0.9	1.1	(0.2)
1.	Total General Service Sales & T-Service	9 420.8	8 757.0	663.8
Contract Sales				
2.1	Rate 100	2.3	4.8	(2.5)
2.2	Rate 110	66.6	69.1	(2.5)
2.3	Rate 115	0.1	(2.1)	2.2
2.4	Rate 135	1.4	5.6	(4.2)
2.5	Rate 145	22.8	22.0	0.8
2.6	Rate 170	48.5	37.8	10.7
2.7	Rate 200	168.7	169.6	(0.9)
2.	Total Contract Sales	310.4	306.8	3.6
Contract T-Service				
3.1	Rate 100	8.0	17.8	(9.8)
3.2	Rate 110	479.5	493.3	(13.8)
3.3	Rate 115	558.5	480.1	78.4
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	60.0	67.4	(7.4)
3.6	Rate 145	161.5	211.2	(49.7)
3.7	Rate 170	474.1	579.4	(105.3)
3.8	Rate 300	30.5	27.6	2.9
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 772.1	1 876.8	(104.7)
4.	Total Contract Sales & T-Service	2 082.5	2 183.6	(101.1)
5.	Total	11 503.3	10 940.6	562.7

* There is no distribution volume for Rate 125 customers.

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 ACTUAL YEAR AND 2010 HISTORIC YEAR
(10^6m^3)

Item No.		Col. 1 2011 Actual Year	Col. 2 2010 Historic Year	Col. 3 2011 Actual Over (Under) 2010 Historic (1-2)	Col. 4 2010* Adjustments	Col. 5 2011 Actual Over (Under) 2010 Historic with Adjustments (3-4)
General Service						
1.1.1	Rate 1 - Sales	3 601.7	3 119.2	482.5	146.8	335.7
1.1.2	Rate 1 - T-Service	1 098.2	1 294.7	(196.5)	51.6	(248.1)
1.1	Total Rate 1	4 699.9	4 413.9	286.0	198.4	87.6
1.2.1	Rate 6 - Sales	2 323.2	1 959.3	363.9	92.0	271.9
1.2.2	Rate 6 - T-Service	2 396.8	2 382.7	14.1	60.5	(46.4)
1.2	Total Rate 6	4 720.0	4 342.0	378.0	152.5	225.5
1.3.1	Rate 9 - Sales	0.8	1.0	(0.2)	0.0	(0.2)
1.3.2	Rate 9 - T-Service	0.1	0.1	0.0	0.0	0.0
1.3	Total Rate 9	0.9	1.1	(0.2)	0.0	(0.2)
1.	Total General Service Sales & T-Service	9 420.8	8 757.0	663.8	350.9	312.9
Contract Sales						
2.1	Rate 100	2.3	4.8	(2.5)	0.1	(2.6)
2.2	Rate 110	66.6	69.1	(2.5)	0.2	(2.7)
2.3	Rate 115	0.1	(2.1)	2.2	0.0	2.2
2.4	Rate 135	1.4	5.6	(4.2)	0.0	(4.2)
2.5	Rate 145	22.8	22.0	0.8	1.0	(0.2)
2.6	Rate 170	48.5	37.8	10.7	0.7	10.0
2.7	Rate 200	168.7	169.6	(0.9)	2.4	(3.3)
2.	Total Contract Sales	310.4	306.8	3.6	4.4	(0.8)
Contract T-Service						
3.1	Rate 100	8.0	17.8	(9.8)	0.2	(10.0)
3.2	Rate 110	479.5	493.3	(13.8)	1.1	(14.9)
3.3	Rate 115	558.5	480.1	78.4	0.1	78.3
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	60.0	67.4	(7.4)	0.0	(7.4)
3.6	Rate 145	161.5	211.2	(49.7)	2.9	(52.6)
3.7	Rate 170	474.1	579.4	(105.3)	6.8	(112.1)
3.8	Rate 300	30.5	27.6	2.9	0.0	2.9
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 772.1	1 876.8	(104.7)	11.1	(115.8)
4.	Total Contract Sales & T-Service	2 082.5	2 183.6	(101.1)	15.5	(116.6)
5.	Total	11 503.3	10 940.6	562.7	366.4	196.3

*Note: Weather normalization adjustments have been made to the 2011 Actual utilizing 2010 Actual Degree Days in order to place the two years on a comparable basis.

Witnesses: R. Lei
S. Qian

The principal reasons for the variances contributing to the weather normalized increase of 196.3 10^6m^3 in the 2011 Actual over the 2010 Historic are as follows:

1. The volumetric increase of 87.6 10^6m^3 in Rate 1 is due to a higher average use per customer totaling 11.5 10^6m^3 and a favorable customer variance of 76.1 10^6m^3;

2. The volumetric increase of 225.5 10^6m^3 in Rate 6 is due to a customer growth of 184.6 10^6m^3 and net customer migration from Contract Sales and T-Service of 61.9 10^6m^3; partially offset by a lower average use per customer of 21.0 10^6m^3;

3. The volumetric decrease of 0.2 10^6m^3 in Rate 9 was due to the loss of 12 stations of 1.0 10^6m^3; partially offset by a higher average use per station of 0.8 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 116.6 10^6m^3 was due to decreases in the apartment sector of 35.6 10^6m^3, the commercial sector of 84.1 10^3m^3 and Rate 200 of 3.3 10^6m^3; partially offset by an increase in the industrial sector of 6.4 10^6m^3.

Witnesses: R. Lei
S. Qian

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011 Actual Year	2012 Bridge Year Estimate	2013 Budget
Residential		2,975	2,869	2,844	2,831	2,786	2,716	2,680	2,670	2,640	2,593	2,562	2,523	2,492	2,491
	Change		(106)	(25)	(13)	(45)	(70)	(36)	(10)	(30)	(47)	(31)	(39)	(31)	(1)
	% Change		-3.56%	-0.87%	-0.46%	-1.59%	-2.51%	-1.33%	-0.37%	-1.12%	-1.78%	-1.20%	-1.52%	-1.23%	-0.04%
Apartment		79,237	79,588	80,512	81,828	81,783	78,307	85,577	99,377	123,734	141,644	161,844	150,684	159,642	151,222
	Change		351	924	1,316	(45)	(3,476)	7,270	13,800	24,357	17,910	20,200	(11,160)	8,958	(8,420)
	% Change		0.44%	1.16%	1.63%	-0.05%	-4.25%	9.28%	16.13%	24.51%	14.47%	14.26%	-6.90%	5.94%	-5.27%
Commercial		17,249	17,042	17,001	17,000	16,877	16,470	16,614	17,066	17,931	18,530	19,203	19,461	19,772	19,648
	Change		(207)	(41)	(1)	(123)	(407)	144	452	865	599	673	258	311	(124)
	% Change		-1.20%	-0.24%	-0.01%	-0.72%	-2.41%	0.87%	2.72%	5.07%	3.34%	3.63%	1.34%	1.60%	-0.63%
Industrial		57,075	54,320	51,791	54,856	50,563	51,424	53,620	58,779	73,938	88,264	106,163	108,872	113,866	108,350
	Change		(2,755)	(2,529)	3,065	(4,293)	861	2,196	5,159	15,159	14,326	17,899	2,709	4,994	(5,516)
	% Change		-4.83%	-4.66%	5.92%	-7.83%	1.70%	4.27%	9.62%	25.79%	19.38%	20.28%	2.55%	4.59%	-4.84%

* All historical average uses are on a calendar-year basis and have been normalized to the 2013 Budget degree days.

Witnesses: R. Lei
S. Qian

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011 Actual Year	2012 Bridge Year Estimate	2013 Budget
Rate 1		2,975	2,869	2,844	2,831	2,786	2,716	2,680	2,670	2,640	2,593	2,562	2,523	2,492	2,491
	Change		(106)	(25)	(13)	(45)	(70)	(36)	(10)	(30)	(47)	(31)	(39)	(31)	(1)
	% Change		-3.56%	-0.87%	-0.46%	-1.59%	-2.51%	-1.33%	-0.37%	-1.12%	-1.78%	-1.20%	-1.52%	-1.23%	-0.04%
Rate 6		21,565	21,221	21,093	21,275	20,970	20,447	20,960	22,243	24,871	26,685	28,873	29,007	29,941	29,132
	Change		(344)	(128)	182	(305)	(523)	513	1,283	2,628	1,814	2,188	134	934	(809)
	% Change		-1.60%	-0.60%	0.86%	-1.43%	-2.49%	2.51%	6.12%	11.81%	7.29%	8.20%	0.46%	3.22%	-2.70%

* All historical average uses are on a calendar-year basis and have been normalized to the 2013 Budget degree days.

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 ACTUAL YEAR AND 2007 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2011 Actual Year	Col. 2 2007 Budget	Col. 3 2011 Actual Over (Under) 2007 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 601.7	2 763.1	838.6
1.1.2	Rate 1 - T-Service	1 098.2	1 723.0	(624.8)
1.1	Total Rate 1	4 699.9	4 486.1	213.8
1.2.1	Rate 6 - Sales	2 323.2	1 446.4	876.8
1.2.2	Rate 6 - T-Service	2 396.8	1 702.3	694.5
1.2	Total Rate 6	4 720.0	3 148.7	1 571.3
1.3.1	Rate 9 - Sales	0.8	5.4	(4.6)
1.3.2	Rate 9 - T-Service	0.1	2.0	(1.9)
1.3	Total Rate 9	0.9	7.4	(6.5)
1.	Total General Service Sales & T-Service	9 420.8	7 642.2	1 778.6
Contract Sales				
2.1	Rate 100	2.3	218.7	(216.4)
2.2	Rate 110	66.6	50.0	16.6
2.3	Rate 115	0.1	41.7	(41.6)
2.4	Rate 135	1.4	5.2	(3.8)
2.5	Rate 145	22.8	41.3	(18.5)
2.6	Rate 170	48.5	57.5	(9.0)
2.7	Rate 200	168.7	150.7	18.0
2.	Total Contract Sales	310.4	565.1	(254.7)
Contract T-Service				
3.1	Rate 100	8.0	1 169.9	(1161.9)
3.2	Rate 110	479.5	570.4	(90.9)
3.3	Rate 115	558.5	864.5	(306.0)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	60.0	50.2	9.8
3.6	Rate 145	161.5	210.5	(49.0)
3.7	Rate 170	474.1	672.5	(198.4)
3.8	Rate 300	30.5	0.0	30.5
3.9	Rate 305	0.0	31.2	(31.2)
3.	Total Contract T-Service	1 772.1	3 569.2	(1797.1)
4.	Total Contract Sales & T-Service	2 082.5	4 134.3	(2051.8)
5.	Total	11 503.3	11 776.5	(273.2)

* There is no distribution volume for Rate 125 customers.

Witnesses: R. Lei
S. Qian

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 ACTUAL YEAR AND 2007 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2011 Actual Year	Col. 2 2007 Budget	Col. 3 2011 Actual Over (Under) 2007 Budget (1-2)	Col. 4 2007* Adjustments		Col. 5 2011 Actual Over (Under) 2007 Budget with Adjustments (3-4)
General Service							
1.1.1	Rate 1 - Sales	3 601.7	2 763.1	838.6	45.9		792.7
1.1.2	Rate 1 - T-Service	1 098.2	1 723.0	(624.8)	31.5		(656.3)
1.1	Total Rate 1	4 699.9	4 486.1	213.8	77.4		136.4
1.2.1	Rate 6 - Sales	2 323.2	1 446.4	876.8	33.4		843.4
1.2.2	Rate 6 - T-Service	2 396.8	1 702.3	694.5	37.2		657.3
1.2	Total Rate 6	4 720.0	3 148.7	1 571.3	70.6		1 500.7
1.3.1	Rate 9 - Sales	0.8	5.4	(4.6)	0.0		(4.6)
1.3.2	Rate 9 - T-Service	0.1	2.0	(1.9)	0.0		(1.9)
1.3	Total Rate 9	0.9	7.4	(6.5)	0.0		(6.5)
1.	Total General Service Sales & T-Service	9 420.8	7 642.2	1 778.6	148.0		1 630.6
Contract Sales							
2.1	Rate 100	2.3	218.7	(216.4)	2.8		(219.2)
2.2	Rate 110	66.6	50.0	16.6	0.1		16.5
2.3	Rate 115	0.1	41.7	(41.6)	0.0	**	(41.6)
2.4	Rate 135	1.4	5.2	(3.8)	0.0		(3.8)
2.5	Rate 145	22.8	41.3	(18.5)	0.1		(18.6)
2.6	Rate 170	48.5	57.5	(9.0)	0.0	**	(9.0)
2.7	Rate 200	168.7	150.7	18.0	10.0		8.0
2.	Total Contract Sales	310.4	565.1	(254.7)	13.0		(267.7)
Contract T-Service							
3.1	Rate 100	8.0	1 169.9	(1161.9)	18.9		(1180.8)
3.2	Rate 110	479.5	570.4	(90.9)	0.9		(91.8)
3.3	Rate 115	558.5	864.5	(306.0)	0.1		(306.1)
3.4	Rate 125	0.0	0.0	0.0	0.0		0.0
3.5	Rate 135	60.0	50.2	9.8	0.0	**	9.8
3.6	Rate 145	161.5	210.5	(49.0)	1.9		(50.9)
3.7	Rate 170	474.1	672.5	(198.4)	2.7		(201.1)
3.8	Rate 300	30.5	0.0	30.5	0.0		30.5
3.9	Rate 305	0.0	31.2	(31.2)	0.0		(31.2)
3.	Total Contract T-Service	1 772.1	3 569.2	(1797.1)	24.5		(1821.6)
4.	Total Contract Sales & T-Service	2 082.5	4 134.3	(2051.8)	37.5		(2089.3)
5.	Total	11 503.3	11 776.5	(273.2)	185.5		(458.7)

*Note: Weather normalization adjustments have been made to the 2007 Budget utilizing the 2011 Actual degree days in order to place the two years on a comparable basis.

** Less than 50,000 m³.

Witnesses: R. Lei
S. Qian

The principal reasons for the variances contributing to the weather normalized decrease of 458.7 10^6m^3 in the 2011 Actual Year over the 2007 Board Approved Budget are as follows:

1. The volumetric increase of 136.4 10^6m^3 in Rate 1 is due to a favourable customer variance of 343.1 10^6m^3; partially offset by lower average use per customer totaling 206.7 10^6m^3;

2. The volumetric increase of 1,500.7 10^6m^3 in Rate 6 is due to net customer migration from Contract Sales and T-Service of 1,275.0 10^6m^3, customer growth of 315.2 10^6m^3; partially offset by a lower average use per customer totaling 89.5 10^6m^3;

3. The volumetric decrease of 6.5 10^6m^3 in Rate 9 is due to a lower average use per station totaling 4.7 10^6m^3 and the loss of stations of 1.8 10^6m^3;

4. The volumetric decrease for Contract Sales and T-Service of 2,089.3 10^6m^3 is due to decreases in the apartment sector of 670.4 10^6m^3, in the commercial sector of 673.2 10^6m^3 and in the industrial sector of 753.7 10^6m^3; partially offset by increase in Rate 200 8.0 10^6m^3. The decreases are primarily attributable to net customer migration to General Service of 1,275.0 10^6m^3 as stated above, and one large distributed energy customer with distribution volume of 202.0 10^6m^3 migrating from Rate 115 to Rate 125 that has no distribution volume effective July 1, 2008.

Witnesses: R. Lei
S. Qian

GENERAL SERVICE AVERAGE USES
HISTORICAL NORMALIZED ACTUAL AND BOARD APPROVED
FISCAL AND CALENDAR YEARS

1. In order to compare the year over year variance between actual and Board Approved normalized average uses on the same basis, each year actual results have to be normalized to the corresponding Board Approved degree days for that year. As both of historical Board Approved degree days and average uses were developed based upon a fiscal year ended September 30 up to 2005, they are presented on a fiscal-year basis up to 2005 in this exhibit. From 2006 onwards, they are presented on a calendar year basis.

2. The actual average uses on page 3 of this exhibit have been normalized to the corresponding Board Approved Conventional degree days for that year as indicated in Table 1.

3. The average uses on page 3 of this exhibit are different from those presented at Exhibit C5, Tab 2, Schedule 3. The average uses filed at Exhibit C5, Tab 2, Schedule 3 are all normalized to the test year degree days instead of each year's corresponding Board Approved degree days and they are all presented on a calendar-year basis.

Witnesses: R. Lei
S. Qian

Table 1

Summary of Actual and Board Approved Degree Days

	Test Year	Col. 1 Actual Degree Days	Col. 2 Budget Degree Days	Col. 3 Variance Degree Days (1)-(2)
FISCAL YEAR	2000	3,526	3,929	(403)
	2001	3,766	3,808	(42)
	2002	3,362	3,700	(338)
	2003	4,029	3,565	464
	2004	3,774	3,565	209
	2005	3,728	3,752	(24)
CALENDAR YEAR	2006	3,448	3,745	(297)
	2007	3,613	3,617	(4)
	2008	3,750	3,543	207
	2009	3,764	3,514	250
	2010	3,454	3,546	(92)
	2011	3,597	3,602	(5)

Witnesses: R. Lei
S. Qian

GENERAL SERVICE AVERAGE USES

	Test Year	Rate Classes	Col. 1 Actual Normalized Average Use (m^3)	Col. 2 Board Approved Normalized Average Use (m^3)	Col. 3 Variance Normalized Average Use (1-2)	Col. 4 %Variance Normalized Average Use (3/2)*100
FISCAL YEAR	2000	Rate 1	3,238	3,218	20	0.6%
		Rate 6	23,560	22,842	718	3.1%
		Total General Service	5,149	5,092	57	1.1%
	2001	Rate 1	3,014	3,044	(30)	-1.0%
		Rate 6	22,510	22,643	(133)	-0.6%
		Total General Service	4,817	4,861	(44)	-0.9%
	2002	Rate 1	2,980	2,970	10	0.3%
		Rate 6	22,097	22,125	(28)	-0.1%
		Total General Service	4,710	4,756	(46)	-1.0%
	2003	Rate 1	2,877	2,892	(15)	-0.5%
		Rate 6	21,593	21,685	(92)	-0.4%
		Total General Service	4,541	4,579	(38)	-0.8%
	2004*	Rate 1	2,843	2,857	(14)	-0.5%
		Rate 6	21,472	21,612	(140)	-0.6%
		Total General Service	4,461	4,502	(41)	-0.9%
	2005	Rate 1	2,890	2,953	(63)	-2.1%
		Rate 6	22,241	22,507	(266)	-1.2%
		Total General Service	4,547	4,646	(99)	-2.1%
CALENDAR YEAR	2006	Rate 1	2,796	2,850	(54)	-1.9%
		Rate 6	22,272	21,999	273	1.2%
		Total General Service	4,444	4,438	6	0.1%
	2007	Rate 1	2,726	2,687	39	1.5%
		Rate 6	22,783	21,010	1,773	8.4%
		Total General Service	4,412	4,200	212	5.0%
	2008	Rate 1	2,636	2,647	(11)	-0.4%
		Rate 6	24,869	24,204	665	2.7%
		Total General Service	4,493	4,449	44	1.0%
	2009	Rate 1	2,604	2,637	(33)	-1.3%
		Rate 6	27,281	28,165	(884)	-3.1%
		Total General Service	4,659	4,770	(111)	-2.3%
	2010	Rate 1	2,579	2,622	(43)	-1.6%
		Rate 6	29,106	27,949	1,157	4.1%
		Total General Service	4,403	4,705	(302)	-6.4%
	2011	Rate 1	2,594	2,643	(49)	-1.9%
		Rate 6	29,471	28,029	1,442	5.1%
		Total General Service	4,807	4,726	81	1.7%

* 2004 Bridge Year Estimate from RP-2003-0203 was reported at column 2 because Board Approved numbers are not available due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

Witnesses: R. Lei
S. Qian

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

1. In order to compare the year over year variance between actual and Board Approved normalized average use, each year's actual results have to be normalized to the corresponding Board Approved degree days for that year. As both of historical Board Approved degree days and average uses were developed based upon a fiscal year ended September 30 up to 2005, they are presented on a fiscal year basis up to 2005 in this exhibit. From 2006 onwards, they are presented on a calendar year basis.

2. The actual average consumption on page 3 of this exhibit has been normalized to the corresponding Board Approved Conventional degree days for that year as indicated in Table 1. Contract market customers' volumes are much less weather sensitive than General Service customer's as illustrated in Exhibit C5, Tab 2, Schedule 6.

Witnesses: R. Lei
S. Qian

Table 1

Summary of Actual and Board Approved Degree Days

	Test Year	Col. 1 Actual Degree Days	Col. 2 Budget Degree Days	Col. 3 Variance Degree Days (1)-(2)
FISCAL YEAR	2000	3,526	3,929	(403)
	2001	3,766	3,808	(42)
	2002	3,362	3,700	(338)
	2003	4,029	3,565	464
	2004	3,774	3,565	209
	2005	3,728	3,752	(24)
CALENDAR YEAR	2006	3,448	3,745	(297)
	2007	3,613	3,617	(4)
	2008	3,750	3,543	207
	2009	3,764	3,514	250
	2010	3,454	3,546	(92)
	2011	3,597	3,602	(5)

Witnesses: R. Lei
S. Qian

Table 2
CONTRACT CUSTOMERS NORMALIZED VOLUME

	Test Year	Col. 1 Actual Normalized Consumption (10^6m^3)	Col. 2 Board Approved Normalized Consumption (10^6m^3)	Col. 3 Variance Normalized Consumption (1-2)	Col. 4 %Variance Normalized Consumption (3/2)*100
FISCAL YEAR	2001	4,292.5	4,517.1	(224.6)	-5.0%
	2002	4,433.6	4,355.6	78.0	1.8%
	2003	4,380.7	4,400.2	(19.5)	-0.4%
	2004*	4,275.7	4,309.7	(34.0)	-0.8%
	2005	4,199.2	4,334.2	(135.0)	-3.1%
CALENDAR YEAR	2006	4,119.1	4,387.9	(268.8)	-6.1%
	2007	3,739.8	4,134.3	(394.5)	-9.5%
	2008	3,099.6	3,355.2	(255.6)	-7.6%
	2009	2,191.4	2,316.6	(125.2)	-5.4%
	2010	2,175.7	2,008.6	167.1	8.3%
	2011	2,082.5	2,022.9	59.6	2.9%

* 2004 Bridge Year Estimate from RP-2003-0203 was reported at Column 2 because Board Approved numbers are not available due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

Witnesses: R. Lei
S. Qian

DETAILS OF OTHER REVENUE
2011 ACTUAL YEAR AND 2007 BOARD APPROVED

Item No.		Col. 1 2011 Actual Year ($Millions)	Col. 2 2007 Board Approved ($Millions)	Col. 3 2011 Actual Over/(Under) 2007 Board Approved ($Millions)
1.1	Service Charges & DPAC	13.2	11.9	1.3
1.2	Rental Revenue - NGV Program	0.5	1.3	(0.8)
1.3	Late Payment Penalties	13.2	8.0	5.2
1.4	Dow Moore Recovery	0.3	0.3	-
1.5	NGV merchandising revenue (net)	-	0.1	
1.6	Transactional Services (net)	8.0	8.0	-
1.7	Miscellaneous	0.8	0.1	0.7
1.8	Open Bill Revenue	5.4	5.4	-
1.9	Total Other Revenue	41.4	35.1	6.3

Witnesses: R. Lei
S. Qian

GAS COSTS, TRANSPORTATION, AND STORAGE

1. The purpose of this evidence is to provide an overview of the gas cost consequences of the gas supply activities, including storage and transportation of Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") during the 2013 Test Year. The process for calculating budgeted gas costs is consistent with prior years. Using the forecasted volumetric demand requirements the Company develops a gas supply plan using a model known as "SENDOUT". This model determines the optimum monthly supply portfolio using existing contractual parameters, i.e., transportation contracts including storage deliverability. It also provides the Company with a forecast of monthly storage targets. Once the monthly supply portfolio and storage targets have been established then gas costs can be calculated.

Gas Supply

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

- Western Canadian Supplies: These supplies source gas in the supply area of Western Canada and will be transported either via TransCanada PipeLines Limited ("TransCanada" or "TCPL") or via Alliance Pipeline to the Company's franchise area.
- Ontario Production: The Ontario supply is *de minimus* in relative terms.
- Peaking contracts: These contracts source gas from other suppliers in the Eastern Zone during the winter season.

Witnesses: J. Sarnovsky
D. Small

- Chicago Supply: These supplies are to be acquired in Chicago and transported to Dawn via the Company's contracted capacity on the Vector Pipeline.
- Delivered Supply: These supplies are forecasted to be acquired directly at the Dawn. However, the Company may consider alternative sources such as western Canadian supply utilizing TCPL Short-Term Firm Transportation ("STFT") capacity either for economic or operational reasons.

3. Enbridge currently buys all of its gas on an indexed basis. It does not have any existing contracts that provide supply on a fixed price basis. Enbridge expects to continue this practice for its 2013 gas supply arrangements.

4. The following is Enbridge's forecast of gas supply acquisition during the test year:

	Volume	
Contract Type	10^6m^3	Bcf
Western Canadian Supply	3 686.1	130.1
Ontario Production	0.7	0.0
Peaking	38.0	1.3
Chicago Supply	1 832.1	64.7
Delivered Supply	1 478.3	52.2
	7 035.2	248.3

Commodity Costs

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

Witnesses: J. Sarnovsky
D. Small

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

7. The Company prepared its gas supply forecast based upon a 21-day average of various indices from August 3, 2011 to August 31, 2011 for the 12 months commencing January 1, 2013 (Exhibit D3, Tab 3, Schedule 4) and applied these monthly prices to the 2013 budgeted annual volume gas purchases.

8. In an effort to isolate the impact of commodity costs changes the Company removed the impact of the updated price forecast and the October 1, 2011 QRAM prices in a fashion similar to the 2011 Budget that was filed in EB-2010-0146.

9. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2013 Purchase Gas Vairance Account ("PGVA"). Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2013 PGVA. While the Company has prepared the 2013 forecast assuming that it will be acquiring gas in 2013 via traditional transportation paths (i.e., TCPL, Alliance/Vector) the possibility does exist in the future to acquire gas via alternative means (i.e., Shale Gas, Rockies, Renewable Natural Gas).

Peak Day Coverage

10. Enbridge has completed a Design Criteria Study which concludes that it is prudent to propose a change in the current degree day assumptions utilized to determine Peak Day Demand under Design conditions. The Company is proposing that for its 2013 Test Year, the Ontario Energy Board (the "Board") approve the outcomes of

the study. The new Design Criteria Study can be found at Exhibit D1, Tab 2, Schedule 3. The Company has however, prepared its 2013 Gas Cost budget assuming the same Peak Day as was forecasted for 2012 in EB-2011-0277. This assumes the continuation of the existing Design Day methodology that uses 39.5 degree days (Celsius) for the coldest peak. Based upon the information that was available at the time Enbridge is currently forecasting a design peak day level of 99 280 10^3m^3 (3.5 Bcf) during the winter season of the 2013 test year which is the same as the forecast used for fiscal 2012.

11. As a part of its Gas Supply evidence for 2012 (EB-2011-0277, Exhibit B, Tab 4, Schedule 1, page 4, paragraph 11) the Company discussed reasons why it reduced its overall level of traditional Peaking Services as part of its gas supply portfolio for 2012. The Company believes that the failure to deliver during periods of high demand in January and February of 2011 are justification to maintain the same level of Peaking Supplies for 2013 as was forecast for 2012. The Company is forecasting that it will meet its Peak Day requirement for 2013 in a similar fashion to the forecast for 2012. A breakdown of the Peak Day requirement and supply forecast are shown at Exhibit D3, Tab 3, Schedule 3.

12. Unlike 2012 however, when the Company forecasted an incremental 75,000 Gj's per day (when compared to 2011) of STFT capacity for three months to help meet its peak and seasonal demand there will be unutilized STFT capacity in 2013 based upon the 2013 budgeted demand forecast. Assuming current TCPL tolls the cost consequences of the unutilized capacity will be $8.3 million. As in prior decisions the Company is entitled to capture as part of its gas cost forecast the cost consequences of any forecasted unutilized long haul TCPL transportation costs.

Witnesses: J. Sarnovsky
D. Small

These costs are captured as part of the forecasted Storage and Transportation charges that can be found at Exhibit D3, Tab 3, Schedule 2, page 1, line item 1.5. These costs are not captured within the PGVA as stated in the description of the PGVA which precludes any forecasted or unforecasted Unabsorbed Deamdn Change ("UDC") to be included in the derivation of the PGVA. The Company is allowed however, to include in the PGVA the impact of changes in TCPL tolls on any forecasted UDC amount.

13. As mentioned above the Company, will be seeking approval of a new Design Criteria in 2013. If the Board were to accept the Company's proposal then there will be a requirement to recover any incremental costs associated with meeting that increase in Peak Day Demand. Based upon the Company's calculation the increase in Peak Day Demand will be approximately 350,000 GJ's under the new criteria. In order to satisfy that Peak Day Demand, the Company will require additional firm transport. As mentioned previously the Company believes the only viable option available to meet that increase in Peak Day Demand currently is through longhaul TCPL STFT capacity. It is the Company's belief that it would not be prudent to assume that the increase in Peak Day demand could be met with traditional firm peaking supply arrangements. While purchasing gas at Dawn may be seen as an alternative from a price perspective, the dilemma remains that buying gas at Dawn to meet Peak Day still requires some form of transport to get that gas to the franchise area. Contracting for additional transportation capacity on Union to get the gas from Dawn to Parkway (if available) would still require transportation on TCPL to get the gas from Parkway to the Central Delivery Area ("CDA") and currently there is no short haul capacity available on TCPL for that path. Another option may be to assume the acquisition of the Marcellus supply, however even if the Company could receive gas at the Niagara receipt point, the

problem remains that no transportation is currently available to get the gas from Niagara to Parkway and then to the CDA. Therefore, the only option available at this time is longhaul STFT on TCPL. Based upon the overall demand in 2013 the Company will experience even greater unutilized cost consequences. The impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million of unutilized transportation cost impacts in total.

14. The Company acknowledges the potential size of this cost and proposes to possibly lessen the impact by not immediately capturing in rates any incremental cost associated with the increase in Design Criteria. The Company is proposing that should the Board approve the new Design Day Study, rather than update its 2013 gas cost forecast to include the incremental $66.2 million that a separate deferral account be created. This deferral account would only capture these costs should they actually occur. If, for example, between now and the start of the 2013 fiscal year other firm supply options become available such as discounted transportation, increased access to Marcellus Shale or construction projects that would increase the take away capacity from Parkway to the franchise area then the possibility exists that a portion if not all of this incremental cost could be avoided.

Transportation

15. Enbridge has a number of Firm Transportation ("FT") and other service entitlements in place for system gas sourced in Western Canada or in the United States (at the Chicago hub as well as U.S. supply area), or both, during the test year. These include service entitlements with TransCanada, Alliance Pipeline and Vector Pipeline. For purposes of this forecast contracts were priced based upon current tolls and contracts that had an expiry date during the Test Year were deemed to be renewed with the following exceptions.

16. For the purposes of the 2013 forecast the Company has assumed the assignment of 50,000 Gj/day of TCPL shorthaul capacity to Direct Purchase customers and will acquire 50,000 Gj/day of TCPL STFT from November to March.

17. The Company had taken a one year assignment of TCPL-FT Empress to Iroquois capacity effective November 1, 2011 and for purposes of the 2013 forecast has assumed that it will contract for long haul TCPL – FT Empress to CDA in the amount of 25,000 Gj's per day effective November 1, 2012.

18. The Company also has M12 service entitlements with Union Gas totaling 2,225,102 Gj/d (2,081 MMcf/d) for delivery of gas by Union at Dawn for storage injection or onward transportation, for gas withdrawn from storage at Tecumseh or Union, or both, and for gas sourced in Western Canada or the United States, or both, and delivered at Dawn for onward transportation. The Company also has M16 transportation capacity with Union to facilitate the Chatham "D" Storage pool. The gas cost forecast assumed January 1, 2011 Union tolls.

Storage

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

20. Enbridge also held a storage entitlement with Union Gas Limited for 21,259,700 Gj broken down into three contracts with varied expiry dates. In its decision in the NGEIR proceeding, dated November 7, 2006, the Board ruled that these contracts

should be priced at cost of service rates and that a phased in approach to market based storage was in the best interests of customers in Ontario. All three of these contracts have expired and effective April 1, 2010 all of the Company's contracted third party storage is at market based rates

21. During 2012, the Company will be required to issue an Request for Proposal for a storage contract that will expire March 31, 2013. For purposes of the 2013 forecast the cost impacts of the current contract are assumed to be continued in the forecast for 2013 gas costs.

Energy Content

22. Enbridge has used a gross heating value of 37.69 MJ/m^3 to convert quantities (i.e., Gj, Dth) into volumes (i.e., 10^3m^3, MMcf). Quantities are the units specified in many of Enbridge's gas purchase and transportation service agreements, whereas Enbridge rates are volumetric.

Relief Requested

23. Based on the evidence above the Company requests recovery of its Gas Cost forecast for 2013.

Witnesses: J. Sarnovsky
D. Small

UPDATED EVIDENCE

1. The Company has updated its' Gas Cost forecast for 2013 to reflect a volumetric change and to incorporate the April 2012 QRAM prices as filed in EB-2012-0054. Details of the volumetric update can be found at Exhibit C1, Tab 3, Schedule 2, filed 2012-06-01. As a consequence of the volumetric update the Company's gas supply portfolio forecast for 2013 has been updated as well. Please see the update to Exhibit D3, Tab 3, Schedule 1, pages 1 and 2, as well as Schedule 2, Schedule 4 and Schedule 5. As the updated exhibits show, the increase in the volumetric forecast is accommodated by an increase in western Canadian supplies, which in this case would be transported via TCPL longhaul STFT capacity.

2. In the original Gas Supply evidence (EB-2011-0354 Exhibit D1, Tab 2, Schedule 1, page 4, Paragraph 12) the Company described that for the 2013 Test Year it intended to continue to forecast 75,000 Gj's of TCPL STFT capacity for three months to help meet its' needs for peak and seasonal demand. For purposes of this update that requirement has not changed, however, as a result of the increase in demand the forecasted utilization of that capacity has increased. The original forecast had assumed that the cost consequences of the unutilized capacity was $8.3 million; based on the updated volumetric forecast that amount has been reduced to $2.8 million assuming current TCPL tolls.

3. In the original evidence the Company also identified that it would be bringing forward a new Design Criteria Study. The Company discussed that given the current transportation available that the only option would be to increase the level of TCPL longhaul STFT. Based on the demand forecast filed at that time, the impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million

in total of unutilized transportation costs impacts. Based on the updated volumetric forecast the total cost impact on 2013 gas costs would be $69.0 million.

4. The Company is continuing to propose that should the Board accept the new Design Criteria Study that the incremental $66.2 million in gas costs be captured in a separate deferral account and that the deferral account would only capture these costs should they occur (please refer to Exhibit D1, Tab 2, Schedule 1, page 6, Paragraph 14) .

Witnesses: J. Sarnovsky
D. Small

OPERATING MAINTENANCE AND OTHER COSTS

1. The purpose of this evidence is to present Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") Operating and Maintenance ("O&M") expense of $426.1 million for the 2013 Test Year ("2013 Budget"). Enbridge's O&M expense is comprised of the cost to carry out the required business activities for each department within Enbridge. Summaries of projected costs by cost type and year over year variance explanations are provided at Exhibit D3, Tab 2, Schedule 3, and Exhibit D4, Tab 2, Schedule 4.

2013 Budget

2. The 2013 O&M budget is a consolidation of the traditional 'grassroots' budget prepared by all departments within Enbridge in accordance with the guidelines and assumptions set forth in the Budget Letter. The budget was developed in consideration of the Company's key business objectives of a continued focus on safety and reliability, customer service, and adherence to legislative and regulatory requirements. The O&M budget was reviewed and approved by the Executive Management Team (the "EMT").

3. The Company's total O&M is grouped into five categories: Customer Care Service Charges, Regulatory Cost Allocation Methodology ("RCAM"), Demand Side Management ("DSM"), Pension Expense, and Other O&M. The groupings are meant to provide a better insight into the Company's O&M structure and cost drivers. A summary of 2013 O&M Budget and the five categories is provided in Table1 on the following page.

Witnesses: S. Kancharla
R. Lei

Table 1
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
2013 Budget, 2012 Estimate, 2011 Historical, and 2007 Board Approved

Line No.	Categories ($ Millions)	Col. 1 Budget 2013	Col. 2 Estimate 2012	Col. 3 Historical 2011	Col. 4 Board Approved 2007	Col. 5 2013 Budget vs. Estimate 2012	Col. 6 2012 Estimate vs. Historical 2011	Col. 7 2011 Historical vs. Board Approved 2007
1.	Customer Care Service Charges	$89.4	$90.4	$82.6	$90.8	($1.0)	$7.8	($8.2)
2.	Regulatory Cost Allocation Methodology(RCAM)	30.3	30.2	26.7	18.1	0.1	3.5	8.6
3.	Demand Side Management (DSM)	28.6	28.1	28.1	22.0	0.5	0.0	6.1
4.	Pension Expense	27.7	20.6	3.2	1.7	7.1	17.3	1.5
5.	Other O&M	250.0	232.9	215.0	193.6	17.1	17.9	21.4
6.	Total Net Utility O&M Expense	$426.1	$402.2	$355.7	$326.2	$23.9	$46.5	$29.5

4. Within the EB-2011-0226 Customer Care/Customer Information System ("CC/CIS") proceeding which took place in 2011, the Ontario Energy Board (the "Board") approved a Settlement Agreement which established O&M related Customer Care Service Charges of $89.4 million for 2013. Please refer to Exhibit D1, Tab 12, Schedule 1 for a review of the treatment of CC/CIS costs as a result of the ADR Settlement.

5. The RCAM amount of $30.3 million is determined in accordance with the methodology approved by the Board in EB-2006-0034. The Company undertakes an update of the RCAM as approved by the Board to establish amounts for each year. The Company's ongoing review of the RCAM methodology and related processes includes an evaluation and review with intervenor groups. Service schedules underpinning RCAM are thoroughly reviewed and revised by Enbridge on an annual basis. The review results in the appropriate level of specific services, activities, and/or departmental charges from Enbridge Inc. ("EI"), the parent

company of Enbridge. The RCAM amounts embedded in the 2013 Budget and 2012 Estimate are placeholders which will be replaced by the final numbers in later updates. The details of RCAM are explained in evidence at Exhibit D1, Tab 4, Schedule 1.

6. The DSM budget of $28.6 million is driven by the forecasted inflationary rate increase (GDP IPI FDD) of 1.73% over the 2012 Estimate that is based on the Board issued guidelines in EB-2008-0346, dated June 30, 2011. The Company's 2012 DSM Plan was filed with the Board on November 4, 2011 in EB-2011-0295. This plan was developed in consultation with intervenor groups, follows recently issued 2012-2014 DSM Guidelines, and the 2012 DSM Budget was the subject of a complete settlement with intervenors. The DSM evidence can be found at Exhibit D1, Tab 7, Schedule 1.

7. The pension expense established for the 2013 Budget of $27.7 million includes a change from the cash basis of pension expense for rate regulated accounting to the accrual basis of expense. This aligns the aspects of reporting for financial reporting and rate making, which provides more transparency and consistency for the users of the financial statements. The rationale for the accounting change for the pension expense can be found at Exhibit A1, Tab 6, Schedule 2.

8. Other O&M represents the remaining departmental O&M costs net of Customer Care service charges, RCAM, DSM, and pension expense. The year over year variances by major cost type are explained in the following comparison sections.

<u>2013 Budget Comparison to 2012 Estimate – Other O&M</u>

9. The 2013 Other O&M Budget is $250 million. This is an increase of $17.1 million or 7.3% over the 2012 Estimate. The variances by cost type between the two years are summarized on Table 2. The principal drivers of this increase are

identified and articulated below.

Table 2
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2013 Test Year vs. 2012 Bridge Year

Line No.	Particulars ($ millions)	Budget 2013 (a)	Estimate 2012 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$170.9	$160.7	$10.2	6.3%
2.	Benefits	30.5	25.9	4.5	17.4%
3.	Short Term Incentive Program	20.3	19.4	0.8	4.3%
4.	Employee Training and Development	4.1	4.0	0.1	2.4%
5.	Materials and Supplies	5.5	5.5	0.0	0.3%
6.	Outside Services	79.0	77.9	1.1	1.4%
7.	Regulatory Proceeding Costs	7.3	5.8	1.5	25.7%
8.	Consulting	9.5	6.7	2.9	42.7%
9.	Repairs and Maintenance	2.0	1.9	0.0	0.8%
10.	Fleet	10.0	9.8	0.2	2.1%
11.	Rents and Leases	7.7	7.4	0.2	3.1%
12.	Telecommunications	3.7	3.6	0.0	1.4%
13.	Travel and Other Business Expenses	4.9	4.7	0.2	4.0%
14.	Memberships	3.4	3.2	0.2	7.1%
15.	Claims, Damages and Legal Fees	0.8	0.8	0.1	8.2%
16.	Interest on Security Deposits	2.7	1.9	0.8	40.5%
17.	Provision for Uncollectibles	15.2	13.7	1.5	10.7%
18.	Internal Allocations and Recoveries	(25.3)	(25.1)	(0.1)	0.5%
19.	Other	7.1	5.9	1.3	21.3%
20.	Subtotal	359.2	333.7	25.5	7.6%
21.	Capitalization (A&G)	(35.7)	(31.4)	(4.3)	13.6%
22.	Capitalization	(69.2)	(65.3)	(3.9)	6.0%
23.	Non-Utility Allocations	(3.4)	(3.2)	(0.2)	6.5%
24.	Subtotal Net Utility O&M Expense	250.9	233.8	17.1	7.3%
25.	Conservation Services	1.5	7.0	(5.5)	-78.4%
26.	Total Other Utility O&M Expense before Eliminations	252.5	240.8	11.6	4.8%
27.	Regulatory Eliminations				
28.	To eliminate Conservation Services and Overheads	(2.5)	(7.9)	5.5	-68.9%
29.	Total Eliminations	(2.5)	(7.9)	5.5	-68.9%
30.	Total Other Utility O&M Expense	$250.0	$232.9	$17.1	7.3%

10. Salaries and wages are higher by $10.2 million as a result of two drivers: merit

Witnesses: S. Kancharla
R. Lei

increases and new FTE additions. The merit increase follows the Human Resources ("HR") guidance: 3.3% salary increase for non-union employees and 3.5% salary increase for union employees. Increase in staff levels is primarily due to safety requirements for integrity management, leak management, damage detection and prevention, and safety related training. The increase is also a response to increases in customer demands.

11. The benefits increase of $4.5 million is driven by a higher salary base, an increase in FTE's, and other post employment benefits ("OPEB"). OPEB accounts for a $2.9 million increase resulting from the change in accounting methodology; please refer to Exhibit A1, Tab 6, Schedule 2 for the details. The rationale for benefits increase is described at Exhibit D1, Tab 19, Schedule 1.

12. Short term incentive program ("STIP") increase of $0.8 million is reflective of a higher salary base and higher FTE's in 2013.

13. The increase of $1.1 million in outside services is primarily driven by the Envision application operations service contract renewal efforts, which includes assessing and selecting service providers and performing transition activities. Inflationary pressures, market cost adjustments for contracts, and a higher customer base account for the rest of the increase, partially offset by lower incremental costs to revise and implement standards and processes related to leak management.

14. The increase of $1.5 million in regulatory proceeding costs is the result of an anticipated increase in costs in relation to Enbridge's 2013 cost of service rate proceeding. This is due to the anticipated increase in complexity and time required for discovery and review within a cost of service process compared to what has been required each year during Enbridge's IR mechanism for 2008-

2012. The result is an anticipated increase in intervenor costs, consulting costs in relation to studies required for the 2013 rebasing application as agreed to by parties within the EB-2011-0008 proceeding, legal costs, and administrative process related costs.

15. The increase of $2.9 million in consulting is primarily due to incremental services required to achieve the Company's goal of zero safety incidents through the Path to Zero initiative.

16. The increase of $0.8 million in interest on security deposits results from the higher short term interest rate (3.95%) forecasted in 2013, relative to 2.75% in 2012.

17. The Provision for Uncollectible Accounts recognizes that, due to customer default, not all billings will be collected. The 2013 Budget of $15.2 million is $1.5 million higher than 2012 Estimate of $13.7 million. This is driven by higher billed receivables due to customer growth and an increase in commodity price. Commodity prices have been at very low levels and declining since early 2009. The 2012 Estimate assumes that gas supply charge will approximate the very low levels reflected in the October 2011 QRAM. However, the Consensus Wholesale Energy Price Forecast indicates an 8%-11% increase from 2012 to 2013. Therefore a price increase has been assumed in the 2013 Budget.

Table 3
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2012 Bridge Year vs. 2011 Historical Year

Line No.	Particulars ($ millions)	Estimate 2012 (a)	Historic 2011 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$160.7	$145.0	$15.7	10.8%
2.	Benefits	25.9	23.2	2.7	11.8%
3.	Short Term Incentive Program	19.4	22.3	(2.8)	-12.8%
4.	Employee Training and Development	4.0	3.6	0.4	11.8%
5.	Materials and Supplies	5.5	4.8	0.7	13.8%
6.	Outside Services	77.9	62.4	15.5	24.8%
7.	Regulatory Proceeding Costs	5.8	5.8	(0.0)	-0.1%
8.	Consulting	6.7	5.3	1.3	25.0%
9.	Repairs and Maintenance	1.9	1.2	0.8	64.9%
10.	Fleet	9.8	8.9	0.9	10.2%
11.	Rents and Leases	7.4	6.3	1.2	18.6%
12.	Telecommunications	3.6	3.3	0.3	9.8%
13.	Travel and Other Business Expenses	4.7	3.7	1.0	26.4%
14.	Memberships	3.2	2.9	0.3	8.9%
15.	Claims, Damages and Legal Fees	0.8	1.2	(0.4)	-36.9%
16.	Interest on Security Deposits	1.9	1.1	0.8	68.6%
17.	Provision for Uncollectibles	13.7	16.8	(3.1)	-18.4%
18.	Internal Allocations and Recoveries	(25.1)	(24.1)	(1.1)	4.4%
19.	Other	5.9	5.4	0.5	8.5%
20.	Subtotal	333.7	299.2	34.5	11.5%
21.	Capitalization (A&G)	(31.4)	(25.3)	(6.1)	23.9%
22.	Capitalization	(65.3)	(55.0)	(10.3)	18.7%
23.	Non-Utility Allocations	(3.2)	(3.4)	0.2	-6.0%
24.	Subtotal Net Utility O&M Expense	233.8	215.5	18.4	8.5%
25.	Conservation Services	7.0	7.0	0.0	0.3%
26.	Total Other Utility O&M Expense before Eliminations	240.8	222.4	18.4	8.3%
27.	Regulatory Eliminations				
28.	To eliminate Conservation Services and Overheads	(7.9)	(7.4)	(0.5)	6.9%
29.	Total Eliminations	(7.9)	(7.4)	(0.5)	6.9%
30.	Total Other Utility O&M Expense	$232.9	$215.0	$17.9	8.3%

Witnesses: S. Kancharla
R. Lei

2012 Estimate Comparison to 2011 Historical – Other O&M

18. The 2012 Other O&M Estimate is $232.9 million. This is an increase of $17.9 million or 8.3% over the 2011 Historical. The variances by cost type between the two years are summarized on Table 3. The principal drivers of this increase are identified and described below.

19. Salaries and wages are higher by $15.7 million as a result of two drivers: merit increases and new FTE additions. The merit increase follows the HR guidance: 3.3% salary increase for non-union employees and 3.5% salary increase for union employees. Increase in staff levels is primarily due to safety requirements for integrity management, leak management, damage detection and prevention, safety related training, and increased work activities in various functions.

20. The benefits increase of $2.7 million is driven by a higher salary base and additional FTE's, higher prescription costs, dental fees, and an increase in employee utilization of benefits. Please refer to Exhibit D1, Tab 19, Schedule 1 for a detailed explanation of benefit costs.

21. STIP decreases by $2.8 million principally due to the estimate of the corporate performance multiplier relative to 2011, partially offset by an increase in base salary and new staff additions.

22. The increase of $0.7 million in materials and supplies is the result of increased pipeline inspection to meet safety requirements.

23. The increase of $15.5 million in outside services is primarily driven by incremental advertising and community outreach programs, an increase in maintenance and safety activities, higher activities for the sewer lateral program, an increase in IT

hardware and software maintenance, higher program costs for growth opportunities, an increase in units of work, a greater number of required pipeline locates, increased leak survey and corrosion activities, and inflationary pressures for all other outside services.

24. The increase of $1.3 million in consulting is primarily due to the incremental services required to achieve the Company's goal of zero safety incidents through the Path to Zero initiative.

25. The increase of $0.8 million in repairs and maintenance reflects higher storage maintenance costs in relation to compressor parts and instrumentation and higher pipe and fitting maintenance activities.

26. The increase of $0.9 million in fleet is the result of higher vehicle costs driven by higher operating activity, higher fuel costs, and increased maintenance related to work equipment.

27. The increase of $1.2 million in Rents and Leases is mainly due to the planned acquisition of additional office space to accommodate the business growth at the head office facility, and an increase in land easement costs.

28. Travel and other business expenses increase by $1.0 million as a result of inflationary pressures, higher travel costs, and anticipated increased business activity and related travel costs.

29. The increase of $0.8 million in interest on security deposits results from higher short term interest rate forecasted in 2012.

30. The 2012 Provision for Uncollectible Accounts estimate of $13.7 million is $3.1 million lower than the 2011 estimate of $16.8 million. While overall, the 2012 Estimate is lower than that of 2011, the 2012 Estimate reflects an expected increase in the value of billed receivables in 2012, which is more than offset by adjustments required to correct deficiencies in accounts receivable reporting that were recognized in 2011.

<u>2011 Historical Comparison to 2007 Board Approved – Other O&M</u>

31. While the Company has used a grass roots department by department approach to forecast its 2012 and 2013 O&M, the comparison by cost type and by department between 2011 and 2007 cannot be performed in a truly meaningful manner due to two reasons. First, the 2007 other O&M approved by the Board was based on an envelope amount which reflects a lump-sum reduction from the 2007 budget as filed. The Board did not approve individual departmental O&M Budgets. The 2007 Budget by department was not adjusted at the department level to reflect the reduction to the envelope amount. Accordingly, there is no Board Approved O&M budget by cost type and by department. The regulatory presentation of 2007 Board Approved amounts by department in some exhibits is an arbitrary allocation that simply involved prorating the total reduction. It is not a true representation of real costs required for each department. Second, the Company has undergone a series of re-organizations since 2007, the organizational structure today is different from what it was in 2007. An attempt to compare the costs line by line between the two distinct time periods would lead to inaccurate interpretations as the roles and responsibilities of groups within departments have changed.

32. A more appropriate comparison between 2007 Board Approved O&M Expense and 2013 Budget is by cost category as identified in paragraphs 3 to 8 and

Table 1 provided on page 2 of this exhibit. Several of these cost categories are the subject of a separate process and settlement agreement (CC/CIS and DSM) or a Board approved methodology (RCAM). The pension expense is a function of whether it is in a deficit position, a matter beyond the Company's control. The aggregate of the expenses associated with these four categories when subtracted from the Total Net Utility O&M Expense leaves the remainder "Other O&M" of $250 Million. Table 4 below sets out the O&M Expense by each category from 2007 Board Approved to 2013 Budget. The high level year over year variance explanations for Other O&M in historical years from 2007 Actual to 2011Estimate can be found at Exhibit D5, Tab 2, Schedule 5.

Table 4
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
From 2007 Board Approved to 2013 Budget

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.	Categories ($ Millions)	Budget 2013	Estimate 2012	Historical 2011	Actual 2010	Actual 2009	Actual 2008	Actual 2007	Board Approved 2007
1.	Customer Care Service Charges	$89.4	$90.4	$82.6	$87.5	$87.5	$82.5	$89.2	$90.8
2.	Regulatory Cost Allocation Methodology(RCAM)	30.3	30.2	26.7	24.3	21.2	19.1	18.1	18.1
3.	Demand Side Management (DSM)	28.6	28.1	28.1	25.5	24.3	23.1	22.0	22.0
4.	Pension Expense	27.7	20.6	3.2	4.0	2.6	1.7	1.5	1.7
5.	Other O&M	250.0	232.9	215.0	205.5	201.5	197.0	196.0	193.6
6.	Total Net Utility O&M Expense	$426.1	$402.2	$355.7	$346.7	$337.0	$323.4	$326.8	$326.2

Full Time Equivalents ("FTE")

33. The FTE's presented in Table 5 on the following page represent the Company's total gross FTE's before capitalization. A portion of the FTE's is capitalized and, therefore, their compensation and employee related expenses are included in the

capital budget. 2013 FTE's are forecast at 2,287. This is an increase of 56 FTE's over the 2012 Estimate of 2,231FTE's. The increase is primarily due to integrity management (twenty FTE's), worker and public safety (eight FTE's), system operations in work management and extended alliance (seven FTE's), IT support for new business applications and the conversion of contractors (six FTE's), measurement and regulation inspectors (five FTE's), leak management (five FTE's), damage prevention (two FTE's), incident response (two FTE's), and other (one FTE's). Please refer to the FTE evidence filed at Exhibit D3, Tab 2, Schedule 4.

Table 5
Enbridge Gas Distribution
Full Time Equivalents (FTE)
2013 Budget, 2012 Estimate, 2011 Historical, and 2007 Board Approved

Line No.	Salary Bands	Col. 1 Budget 2013	Col. 2 Estimate 2012	Col. 3 Historical 2011	Col. 4 Board Approved 2007	Col. 5 2013 Budget vs. Estimate 2012	Col. 6 2012 Estimate vs. Historical 2011	Col. 7 2011 Historical vs. Board Approved 2007
1.	Management	140	138	129	250	1	9	(121)
2.	Supervisory	1,452	1,393	1,266	955	60	127	310
3.	Union	695	700	675	755	(5)	25	(80)
4.	Total FTE	2,287	2,231	2,070	1,961	56	161	110

34. 2012 FTE's increase by 161 FTE's over the 2011 Historical of 2,070 FTE's. The increase is primarily due to distribution asset management (twenty FTE's), pipeline evaluation and inspection (sixteen FTE's), Operations (fourteen FTE's) needed to improve records integrity, revise standards and processes around leaks, damages, and emergency response times, and replace targeted assets based on risk studies, damage prevention and leak survey and corrosion (twelve FTE's), environmental health and safety (ten FTE's), safety and technical training

Witnesses: S. Kancharla
R. Lei

(ten FTE's), GTA reinforcement project (nine FTE's), customer support (eight FTE's), system operations (seven FTE's), IT system specialists, project manager, and analysts (seven FTE's), Operations union collective agreement (five FTE's), safety supervisors (five FTE's), measurement and regulation inspectors (five FTE's), HR support and plant maintenance (five FTE's), regulatory support and gas control management (five FTE's), DSM and conservation services (five FTE's), an overlap of resources to allow for the training and knowledge transfer (five FTE's), Finance unfilled replacements and return of maternity leave (six FTE's), legal contracts lead and records management (three FTE's), public and government affairs (three FTE's), other (one FTE's). Please refer to the FTE evidence filed at Exhibit D4, Tab 2, Schedule 5 and Exhibit D5, Tab 2, Schedule 4.

O&M Cost Per Customer

35. Table 6 on the following page provides the O&M cost per customer from 2004 to 2013 in constant dollars and in nominal dollars. The inflation index being used for the calculation of constant dollars is GDP IPI FDD, which is consistent with what is used in the IR formula. The O&M cost per customer for 2013, in constant dollars, has slightly increased by 0.2% since 2004 due to FTE growth, increased customer numbers, and higher safety requirements, partially offset by the continued productivity improvements.

Witnesses: S. Kancharla
R. Lei

Table 6
Enbridge Gas Distribution
Operation and Maintenance Expense
Cost Per Customer

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
2013 Constant Dollars per Customer										
Utility O&M Cost Per Customer [1]	197.09	186.14	183.71	180.03	172.30	174.91	173.86	173.16	191.73	197.42
Nominal Dollars per Customer										
Utility O&M Cost Per Customer [1]	168.40	162.44	164.11	164.40	161.02	165.63	166.76	167.35	188.49	197.42
Number of Customers (000's) [2]	1,676.38	1,724.72	1,782.81	1,824.79	1,865.02	1,887.61	1,926.29	1,957.73	1,984.73	2,013.35

Notes:
1. Does not include ancillary program costs, or demand side management costs
2. Number of Customers represent total unlock customers

Summary

36. The level of costs submitted are required to continue to provide an acceptable quality of service to Enbridge's existing and new customers and maintain the distribution system to ensure continued safety and reliability. Enbridge respectfully requests approval of the 2013 O&M Budget of $426.1 million.

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2013 Test Year vs. 2012 Bridge Year

Line No.	Notes:	($ millions)
	Salaries and Wages (Line 1)	
1.	2013 Budget	170.9
2.	2012 Estimate	160.7
3.	Difference	10.2
	Reasons:	
4.	Annual salary and wage increase of 3.3% for non-unions and 3.5% for unions	5.3
5.	Increase of 56 FTE's	4.9
6.	Total 2013 vs. 2012 Difference	10.2
	Benefits (Line 2)	
7.	2013 Budget	30.5
8.	2012 Estimate	25.9
9.	Difference	4.5
	Reasons:	
10.	Increase in OPEB expense due to the change in accounting methodology	2.9
11.	Increase in staff levels - 56 FTE's	0.7
12.	Increase in prescription costs, dental fees, and increase in benefit claims	0.5
13.	Increase in CPP, EI & Employers Health Tax from higher salary base	0.4
14.	Total 2013 vs. 2012 Difference	4.5
	Short Term Incentive Program (Line 3)	
15.	2013 Budget	20.3
16.	2012 Estimate	19.4
17.	Difference	0.8
	Reasons:	
18.	The increased in STIP is a result of the higher salary base in 2013	0.8
19.	Total 2013 vs. 2012 Difference	0.8

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2013 Test Year vs. 2012 Bridge Year

Line No.	Notes:	($ millions)
	Outside Services (Line 6)	
20.	2013 Budget	79.0
21.	2012 Estimate	77.9
22.	Difference	1.1
	Reasons:	
23.	EnVision application operations service contract renewal efforts to assess and select a service provider as well as to perform transition activities	1.1
24.	Additional work relating to in line inspection program	1.0
25.	Higher number of pipeline locates required, increased leak survey and corrosion activities	0.9
26.	Higher contractor cost, inflationary increases for building utility costs	0.5
27.	Inflationary pressures and market cost adjustments for IT contracts	0.4
28.	Increase in inserts, video, first time customer kit, and translation costs	0.4
29.	Contract cost increase for all other departments	0.3
30.	Reduction in contractors cost as a result of conversion of four FTE's	(0.5)
31.	Lower incremental costs for leak management, repairs, and maintenance	(3.0)
32.	Total 2013 vs. 2012 Difference	1.1
	Regulatory costs (Line 7)	
33.	2013 Budget	7.3
34.	2012 Estimate	5.8
35.	Difference	1.5
	Reasons:	
36.	Higher regulatory proceeding costs in anticipation of a more lengthy 2013 cost of service rate application, as compared to recent IR rate applications	1.5
37.	Total 2013 vs. 2012 Difference	1.5

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2013 Test Year vs. 2012 Bridge Year

Line No.	Notes:	($ millions)
	Consulting (Line 8)	
38.	2013 Budget	9.5
39.	2012 Estimate	6.7
40.	Difference	2.9
	Reasons:	
41.	Incremental services required for the Path to Zero initiative	1.9
42.	Envision contract renewal efforts	0.6
43.	Market cost adjustment for contracts	0.4
44.	Total 2013 vs. 2012 Difference	2.9
	Interest on Security Deposits (Line 16)	
45.	2013 Budget	2.7
46.	2012 Estimate	1.9
47.	Difference	0.8
	Reasons:	
48.	The short term interest rate forecast is 120 basis points higher than 2012	0.8
49.	Total 2013 vs. 2012 Difference	0.8
	Provision for Uncollectibles (Line 17)	
50.	2013 Budget	15.2
51.	2012 Estimate	13.7
52.	Difference	1.5
	Reasons:	
53.	higher billed receivables due to customer growth and an increase in commodity price, and a higher risk related to customers' ability to pay	1.5
54.	Total 2013 vs. 2012 Difference	1.5

Witnesses: S. Kancharla
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Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2013 Test Year vs. 2012 Bridge Year

Line No.	Notes:	($ millions)
	Other (Line 19)	
55.	2013 Budget	7.1
56.	2012 Estimate	5.9
57.	Difference	1.3
	Reasons:	
58.	The Company’s performance management initiative aimed at improving overall efficiency and effectiveness	1.3
59.	Total 2013 vs. 2012 Difference	1.3
	Capitalization (A&G) (Line 21)	
60.	2013 Budget	(35.7)
61.	2012 Estimate	(31.4)
62.	Difference	(4.3)
	Reasons:	
63.	Higher pension and OPEB costs	(2.1)
64.	Higher underpinning O&M costs for A&G	(2.1)
65.	Total 2013 vs. 2012 Difference	(4.3)
	Capitalization (Line 22)	
66.	2013 Budget	(69.2)
67.	2012 Estimate	(65.3)
68.	Difference	(3.9)
	Reasons:	
69.	Driven by salary increase and FTE additions in 2013	(3.9)
70.	Total 2013 vs. 2012 Difference	(3.9)
71.	All other items for variances less than $0.5 million	0.8
	Total variance	17.1

Witnesses: S. Kancharla
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Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2012 Bridge Year vs. 2011 Historical Year

Line No.	Notes:	($ millions)
	Salaries and Wages (Line 1)	
1.	2012 Estimate	160.7
2.	2011 Historical	145.0
3.	Difference	15.7
	Reasons:	
4.	Annual salary and wage increase of 3.3% for non-unions and 3.5% for unions	4.8
5.	Increase of 161 FTE's	10.9
6.	Total 2012 vs. 2011 Difference	15.7
	Benefits (Line 2)	
7.	2012 Estimate	25.9
8.	2011 Historical	23.2
9.	Difference	2.7
	Reasons:	
10.	Increase in staff levels - 161 FTE's	1.9
11.	Increase in prescription costs, dental fees, and increase in benefit claims	0.4
12.	Increase in CPP, EI & Employers Health Tax from higher salary base	0.4
13.	Total 2012 vs. 2011 Difference	2.7
	Short Term Incentive Program (Line 3)	
14.	2012 Estimate	19.4
15.	2011 Historical	22.3
16.	Difference	(2.8)
	Reasons:	
17.	Higher corporate performance multipliers in 2011	(2.8)
18.	Total 2013 vs. 2012 Difference	(2.8)

Witnesses: S. Kancharla
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Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2012 Bridge Year vs. 2011 Historical Year

Line No.	Notes:	($ millions)
	Material and Supplies (Line 5)	
19.	2012 Estimate	5.5
20.	2011 Historical	4.8
21.	Difference	0.7
	Reasons:	
22.	Increased pipeline inspection	0.5
23.	Increase in material and supplies for all other department	0.2
24.	Total 2013 vs. 2012 Difference	0.7
	Outside Services (Line 6)	
25.	2012 Estimate	77.9
26.	2011 Historical	62.4
27.	Difference	15.5
	Reasons:	
28.	Advertising and other community outreach related to the safety related initiatives	6.2
29.	Increase in maintenance activities relating to safety and sewer lateral program	4.8
30.	Increase in IT hardware and software maintenance contract costs	1.3
31.	Higher program costs for growth opportunities	1.1
32.	Increase in units of work in Operations	1.0
33.	Higher number of pipeline locates required, increased leak survey and corrosion activities	0.5
34.	Outside services for all other departments	0.7
35.	Total 2012 vs. 2011 Difference	15.5
	Consulting (Line 8)	
36.	2012 Estimate	6.7
37.	2011 Historical	5.3
38.	Difference	1.3
	Reasons:	
39.	the incremental service required to continue the Path to Zero initiative	1.3
40.	Total 2012 vs. 2011 Difference	1.3

Witnesses: S. Kancharla
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Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2012 Bridge Year vs. 2011 Historical Year

Line No.	Notes:	($ millions)
	Repairs and maintenance (Line 9)	
41.	2012 Estimate	1.9
42.	2011 Historical	1.2
43.	Difference	0.8
	Reasons:	
44.	Higher storage maintenance costs associated to compressor parts, instrumentation, and higher pipeline fitting costs	0.8
45.	Total 2012 vs. 2011 Difference	0.8
	Fleet (Line 10)	
46.	2012 Estimate	9.8
47.	2011 Historical	8.9
48.	Difference	0.9
	Reasons:	
49.	Higher vehicle costs driven by higher operating activity, higher fuel costs, and increased maintenance in work equipment	0.9
50.	Total 2012 vs. 2011 Difference	0.9
	Rents and leases (Line 11)	
51.	2012 Estimate	7.4
52.	2011 Historical	6.3
53.	Difference	1.1
	Reasons:	
54.	Planned acquisition of additional office space to accommodate requirements at the head office facility	0.7
55.	Increase in land easement requirements	0.4
56.	Total 2012 vs. 2011 Difference	1.1

Witnesses: S. Kancharla
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Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2012 Bridge Year vs. 2011 Historical Year

Line No.	Notes:	($ millions)
	Travel and other business expenses (Line 13)	
57.	2012 Estimate	4.7
58.	2011 Historical	3.7
59.	Difference	1.0
	Reasons:	
60.	inflationary pressures, higher travel costs, and increase in business activity	1.0
61.	Total 2012 vs. 2011 Difference	1.0
	Interest on Security Deposits (Line 16)	
62.	2012 Estimate	1.9
63.	2011 Historical	1.1
64.	Difference	0.8
	Reasons:	
65.	The short term interest rate forecast is 114 basis points higher than 2011	0.8
66.	Total 2012 vs. 2011 Difference	0.8
	Provision for Uncollectibles (Line 17)	
67.	2012 Estimate	13.7
68.	2011 Historical	16.8
69.	Difference	(3.1)
	Reasons:	
70.	Higher estimates in 2011 due to one time non-recurring adjustments	(3.1)
71.	Total 2012 vs. 2011 Difference	(3.1)

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2012 Bridge Year vs. 2011 Historical Year

Line No.	Notes:	($ millions)
	Internal allocations and recoveries (Line 18)	
72.	2012 Estimate	(25.1)
73.	2011 Historical	(24.1)
74.	Difference	(1.1)
	Reasons:	
75.	Additional safety and records management initiatives driving additional O&M capitalization	(1.1)
76.	Total 2012 vs. 2011 Difference	(1.1)
	Capitalization (A&G) (Line 21)	
77.	2012 Estimate	(31.4)
78.	2011 Historical	(25.3)
79.	Difference	(6.1)
	Reasons:	
80.	Higher pension contribution expense	(3.7)
81.	Higher underpinning O&M costs for A&G	(2.4)
82.	Total 2012 vs. 2011 Difference	(6.1)
	Capitalization (Line 22)	
83.	2012 Estimate	(65.3)
84.	2011 Historical	(55.0)
85.	Difference	(10.3)
	Reasons:	
86.	Driven by salary increase and FTE additions in 2013	(10.3)
87.	Total 2012 vs. 2011 Difference	(10.3)
88.	All other items for variances less than $0.5 million	0.8
	Total variance	17.9

Witnesses: S. Kancharla
R. Lei

UPDATED OPERATING MAINTENANCE AND OTHER COSTS

1. 2011 Historical and 2013 Budget have been updated to reflect 2011 actual results and material changes to the 2013 Test Year since EB-2011-0354 was filed. There were no changes made to the 2012 Estimate.

Table 1
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
2013 Budget, 2012 Estimate, 2011 Actual, and 2007 Board Approved

Line No.	Categories ($ Millions)	Col. 1 Updated Budget 2013	Col. 2 Estimate 2012	Col. 3 Actual 2011	Col. 4 Board Approved 2007	Col. 5 2013 Budget vs. Estimate 2012	Col. 6 2012 Estimate vs. Actual 2011	Col. 7 2011 Actual vs. Board Approved 2007
1.	Customer Care Service Charges	$89.4	$90.4	$79.2	$90.8	($1.0)	$11.2	($11.6)
2.	Regulatory Cost Allocation Methodology(RCAM)	32.1	30.2	26.7	18.1	1.9	3.5	8.6
3.	Demand Side Management (DSM)	31.4	28.1	26.7	22.0	3.3	1.4	4.7
4.	Pension Expense	37.3	20.6	3.2	1.7	16.7	17.3	1.5
5.	Other O&M	247.8	232.9	224.7	193.6	14.9	8.2	31.1
6.	Total Net Utility O&M Expense	$438.1	$402.2	$360.5	$326.2	$35.9	$41.7	$34.4

Witness: S. Kancharla
R. Lei

Table 2
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
2013 Test Year

Line No.	Categories ($ Millions)	Col. 1 Updated Budget 2013	Col. 2 Original Budget 2013	Col. 3 Updated Budget vs. Budget 2013
1.	Customer Care Service Charges	$89.4	$89.4	$0.0
2.	Regulatory Cost Allocation Methodology(RCAM)	32.1	30.3	1.8
3.	Demand Side Management (DSM)	31.4	28.6	2.8
4.	Pension Expense	37.3	27.7	9.6
5.	Other O&M	247.8	250.0	(2.2)
6.	Total Net Utility O&M Expense	$438.1	$426.1	$12.0

2. The 2013 updated total net utility O&M expense increases by $12.0 million from $426.1 million to $438.1 million due to higher RCAM, DSM, and pension expense. Table 2 provided above summarizes the changes in major five cost categories.

- RCAM increases by $1.8 million to reflect MNP's recommended amount of $32.1 million, which replaces the placeholder of $30.3 million in the original rate case filing.

- DSM increases by $2.8 million, which represents 10% increase for the incremental low income program spending.

- Pension expense increases by $9.6 million as a result of the updated report from Mercer.

- Other O&M decreases by $2.2 million due to higher pension expense being capitalized to A&G at a rate of 21.2%.

Witness: S. Kancharla
R. Lei

Table 3
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
2011 Year

Line No.	Categories ($ Millions)	Col. 1 Actual 2011	Col. 2 Historical 2011	Col. 3 Actual vs. Historical 2011
1.	Customer Care Service Charges	$79.2	$82.6	($3.4)
2.	Regulatory Cost Allocation Methodology(RCAM)	26.7	26.7	(0.0)
3.	Demand Side Management (DSM)	26.7	28.1	(1.4)
4.	Pension Expense	3.2	3.2	0.0
5.	Other O&M	224.7	215.0	9.6
6.	Total Net Utility O&M Expense	$360.5	$355.7	$4.8

3. The 2011 Actual net utility O&M was $360.5 million, which was $4.8 million higher than the filed 2011 Historical year of $355.7 million due to higher other O&M partially offset by customer care service charges. Table 3 provided above summarizes the changes in major five cost categories.

- Customer care service charges decreased by $3.4 million due to lower outsourcing charges in billing, credit and collection, meter reading, and postage partially offset by higher call centre service costs.

- DSM decreased by $1.4 million because the actual incremental low income program spending approved by the Board was booked in the DSMVA account as opposed to in the O&M.

- Other O&M increased by $9.6 million primarily as a result of higher provision for uncollectibles and higher short term incentive program.

Witness: S. Kancharla
R. Lei

Table 4
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2013 Test Year vs. 2012 Bridge Year

Line No.	Particulars ($ millions)	Updated Budget 2013 (a)	Estimate 2012 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$170.9	$160.7	$10.2	6.3%
2.	Benefits	30.5	25.9	4.5	17.4%
3.	Short Term Incentive Program	20.3	19.4	0.8	4.3%
4.	Employee Training and Development	4.1	4.0	0.1	2.4%
5.	Materials and Supplies	5.5	5.5	0.0	0.3%
6.	Outside Services	79.0	77.9	1.1	1.4%
7.	Regulatory Proceeding Costs	7.3	5.8	1.5	25.7%
8.	Consulting	9.5	6.7	2.9	42.7%
9.	Repairs and Maintenance	2.0	1.9	0.0	0.8%
10.	Fleet	10.0	9.8	0.2	2.1%
11.	Rents and Leases	7.7	7.4	0.2	3.1%
12.	Telecommunications	3.7	3.6	0.0	1.4%
13.	Travel and Other Business Expenses	4.9	4.7	0.2	4.0%
14.	Memberships	3.4	3.2	0.2	7.1%
15.	Claims, Damages and Legal Fees	0.8	0.8	0.1	8.2%
16.	Interest on Security Deposits	2.7	1.9	0.8	40.5%
17.	Provision for Uncollectibles	15.2	13.7	1.5	10.7%
18.	Internal Allocations and Recoveries	(25.3)	(25.1)	(0.1)	0.5%
19.	Other	7.2	5.9	1.4	23.0%
20.	Subtotal	359.3	333.7	25.6	7.7%
21.	Capitalization (A&G)	(37.7)	(31.4)	(6.3)	20.1%
22.	Capitalization	(69.2)	(65.3)	(3.9)	6.0%
23.	Non-Utility Allocations	(3.4)	(3.2)	(0.2)	6.5%
24.	Subtotal Net Utility O&M Expense	249.0	233.8	15.2	6.5%
25.	Conservation Services	1.5	7.0	(5.5)	-78.4%
26.	Total Other Utility O&M Expense before Eliminations	250.5	240.8	9.7	4.0%
27.	Regulatory Eliminations				
28.	To eliminate Conservation Services and Overheads	(2.5)	(7.9)	5.5	-68.9%
29.	Incremental O&M Allocated to Unregulated Storage	(0.2)	-	(0.2)	
30.	Total Eliminations	(2.7)	(7.9)	5.2	-66.0%
31.	Total Other Utility O&M Expense	$247.8	$232.9	$14.9	6.4%
32.	Management	140	138	2	1.4%
33.	Supervisory	1,452	1,393	59	4.2%
34.	Union	695	700	(5)	-0.7%
35.	FTE	2,287	2,231	56	2.5%

Witness: S. Kancharla
R. Lei

Table 5
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2012 Bridge Year vs. 2011 Actual Year

Line No.	Particulars ($ millions)	Estimate 2012 (a)	Actual 2011 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$160.7	$141.5	$19.2	13.6%
2.	Benefits	25.9	24.3	1.7	6.9%
3.	Short Term Incentive Program	19.4	26.0	(6.6)	-25.3%
4.	Employee Training and Development	4.0	5.6	(1.5)	-27.4%
5.	Materials and Supplies	5.5	5.2	0.3	5.6%
6.	Outside Services	77.9	63.6	14.3	22.4%
7.	Regulatory Proceeding Costs	5.8	4.8	1.0	21.1%
8.	Consulting	6.7	5.0	1.7	33.1%
9.	Repairs and Maintenance	1.9	1.4	0.6	40.3%
10.	Fleet	9.8	9.0	0.8	8.5%
11.	Rents and Leases	7.4	7.3	0.2	2.1%
12.	Telecommunications	3.6	3.1	0.5	15.4%
13.	Travel and Other Business Expenses	4.7	3.5	1.2	32.8%
14.	Memberships	3.2	4.0	(0.8)	-20.6%
15.	Claims, Damages and Legal Fees	0.8	1.6	(0.8)	-52.8%
16.	Interest on Security Deposits	1.9	1.0	0.9	86.6%
17.	Provision for Uncollectibles	13.7	21.5	(7.8)	-36.4%
18.	Internal Allocations and Recoveries	(25.1)	(25.7)	0.6	-2.4%
19.	Other	5.9	6.8	(0.9)	-13.5%
20.	Subtotal	333.7	309.5	24.2	7.8%
21.	Capitalization (A&G)	(31.4)	(24.5)	(6.9)	28.3%
22.	Capitalization	(65.3)	(55.3)	(10.0)	18.1%
23.	Non-Utility Allocations	(3.2)	(4.9)	1.7	-34.2%
24.	Subtotal Net Utility O&M Expense	233.8	224.9	8.9	4.0%
25.	Conservation Services	7.0	7.3	(0.3)	-4.3%
26.	Total Other Utility O&M Expense before Eliminations	240.8	232.2	8.6	3.7%
27.	Regulatory Eliminations				
28.	To eliminate Conservation Services and Overheads	(7.9)	(7.3)	(0.6)	8.6%
29.	Incremental O&M Allocated to Unregulated Storage	-	(0.2)	0.2	-100.0%
30.	Total Eliminations	(7.9)	(7.5)	(0.4)	5.2%
31.	Total Other Utility O&M Expense	$232.9	$224.7	$8.2	3.7%
32.	Management	138	129	9	7.1%
33.	Supervisory	1,393	1,266	127	10.0%
34.	Union	700	675	25	3.7%
35.	FTE	2,231	2,070	161	7.8%

Witness: S. Kancharla
R. Lei

Table 6
Enbridge Gas Distribution
Operation and Maintenance Expense
Cost Per Customer

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
2013 Constant Dollars per Customer										
Utility O&M Cost Per Customer [1]	197.09	186.14	183.71	180.03	172.30	174.91	173.86	176.18	191.73	201.23
Nominal Dollars per Customer										
Utility O&M Cost Per Customer [1]	168.40	162.44	164.11	164.40	161.02	165.63	166.76	170.27	188.49	201.23
Number of Customers (000's) [2]	1,676.38	1,724.72	1,782.81	1,824.79	1,865.02	1,887.61	1,926.29	1,960.38	1,984.73	2,020.96

Notes:
1. Does not include ancillary program costs, or demand side management costs
2. Number of Customers represent total unlock customers

Witness: S. Kancharla
R. Lei

EMPLOYEE EXPENSES AND WORKFORCE DEMOGRAPHICS

1. The purpose of this evidence is to outline the employee-related expenses, particularly those that will increase beyond inflation rates due, in large measure, to changing workforce demographics. An aging workforce and the associated increase in retirements and resulting need to hire and train replacements are costs that many businesses are facing. These costs are not only unavoidable, they are necessary to ensure the continued provision of services at the levels expected and demanded by Enbridge Gas Distribution Inc's ("Enbridge" or the "Company") customers.

2. One issue that the Canadian market has been experiencing over the last number of years is increasing and of concern, namely, the fact that we have an aging working population preparing for retirement at a time when there are fewer skilled workers available to take their place. The risks of skill and resource gaps are significant. At Enbridge currently 19% of our workforce is over the age of 55, and 18% of our employees are eligible to retire. By 2015, 25% of our workforce will be eligible to retire, and by 2020, 40% of our workforce could retire. Considering the potential impacts to our workforce due to retirements, significant efforts are being placed on creating plans to ensure we replace critical skills and knowledge in order to maintain and operate a safe, reliable and cost effective gas distribution system. It is critically important that we are able to attract the best candidates for employment opportunities at the Company which will reflect on the services we provide to our customers.

3. Enbridge is not the only employer that faces such challenges. It must compete for talent with other companies and industries that similarly must look for skilled workers in an aging workforce. These demographic realities impact employee expenses in a number of areas as outlined in this document.

Witness: S. Trozzi

Compensation

4. In order to assess our competitive positioning in relationship to the market, the Company engaged Mercer Canada to conduct a study to benchmark its total compensation plans - See Exhibit D2, Tab 3, Schedule 1, for the Mercer Compensation, Pension and Benefits Study (the "Mercer Study"). Enbridge utilizes a cash compensation package that consists of a fixed component (base salary and wages) plus a variable pay component Short-Term Incentive Program ("STIP"). In addition, senior positions within the utility are eligible for a Long Term Incentive Program ("LTIP") to ensure focus on achievement of long-term Company goals and to incent retention.

5. Compensation levels are competitively based upon market conditions that reflect the local labour market in which the Company competes for talent. Enbridge has a defined comparator group of companies comprised of large organizations (see page 15, Mercer Study). The pay philosophy that the Company utilizes is to target total cash compensation at the 50th percentile (plus or minus 10%), of the market.

6. The Mercer Study indicates that Enbridge is currently slightly below (-3%) market P50 for total cash compensation. The Mercer Study also indicates that Enbridge is slightly below (-2%) market P50 on base salary, and slightly above (2%) market P50 on total compensation. These Mercer results are well within plus or minus 10% of the 50th percentile.

7. The Mercer Study states that the majority of Canadian organizations target the 50th percentile compensation levels which support the Company's compensation philosophy assisting us in maintaining its competitive place in the market. The Company will continue to evaluate its compensation practices on an ongoing basis to ensure labour market competitiveness and the retention of critical skills.

Witness: S. Trozzi

8. Base salary budgets are established annually with consideration given to external compensation consultant's forecasts of salary increases, negotiated wage settlements and consumer price index projections. Enbridge utilizes several external sources to gather this information (The Conference Board of Canada, Towers Watson, Hay Management Consulting, and Mercer Human Resources Consulting).

9. On April 1, 2011, the Company increased non-union salaries by 3.2%. In 2012 and 2013 the collective agreement provides salary increases based on the percentages and dates as follows:
   - January 1, 2012 2%
   - July 1, 2012 1.5%
   - January 1, 2013 2%
   - July 1, 2013 1.5%

10. Salary increases are provided to employees based on the salary budget, market data and individual employee performance.

11. The variable pay component (STIP) is an element of compensation for all permanent employees. It is performance-driven and is intended to focus employees on achieving and exceeding specific corporate, business unit, departmental and/or individual goals that are determined on an annual basis. Company achievements of financial and operational results are tracked through the use of "scorecards" at the Business Unit departmental levels. These measures provide a direct line of sight for employees. They can clearly understand their contributions to the business and the role they play in the achievement of business results. The business unit component of the STIP incentive pay program is tied to achievements of the scorecard results.

12. For each of the scorecard metrics, a minimum performance threshold is established. If actual performance is below the minimum threshold established for a specific metric, there is no payout for that element of the incentive opportunity. In addition, for all non-union employees, there is a minimum threshold of individual performance that must be achieved to be eligible to receive an incentive payout.

13. Executive and senior leadership positions have an LTIP component included within their standard compensation. This is a stock-based plan comprised of three types of awards – Incentive Stock Options ("ISO's"), Performance Stock Units ("PSU's"), and Restricted Share Units ("RSU's"). ISO grants vest equally over four years of continuous employment. PSU's are subject to vesting, but only after a specified performance goal has been achieved. RSU's vest at the end of a three-year period, provided continuous employment is maintained. Eligibility is based on salary grade. Senior executives are eligible for ISO's and PSU's. Directors are eligible for ISO's and RSU's and senior managers are eligible for RSU's.

14. Participation in the LTIP plan is determined by the Human Resources Compensation Committee of the Enbridge Inc. Board of Directors and is restricted to those positions seen to be key from a decision-making and operational accountability perspective. Individual performance ratings and succession criticality are factored into the grant calculation.

15. In addition, other select managers can be nominated for a discretionary RSU grant. Consideration is given to those individuals who are identified as critical to retain due to specialized skills or for succession purposes. Nominations must be approved by the Human Resources Compensation Committee of the Enbridge Inc. Board of Directors.

<u>Benefits and Pension</u>

16. An important element in being able to attract and retain the talent that Enbridge requires is the ability to offer market-competitive pension and benefit plans. This is determined through the Mercer Study.

17. Enbridge provides a total compensation package including pension and benefit plans that are competitive within the Company's market comparator group. Enbridge ensures effective cost management of these plans through intelligent design, efficient utilization, and performance monitoring of the Company's 3^{rd} party service providers.

18. Benefit costs continue to rise. In 2012 benefits increased by $2.7 million and in 2013 they increase by $4.5 million. These increases are due to several factors; (1) Canada Pension Plan, Employment Insurance, and Employers Health Tax increases; (2) additional FTEs which increase benefit costs; (3) increased utilization of the benefit plans and the need for increased services given the aging workforce; and (4) higher prescription costs and dental fees. In 2013 the majority of the increase is due to a change in accounting practices from Canadian GAAP to US GAAP which amounts to $2.9 million.

19. Enbridge provides a flexible benefit plan for all employees (both union and non-union). Employees receive an annual amount of "flex credits" that can be applied to purchase a customized list of benefits that best suit their needs. Rather than offering a "one size fits all" suite of benefits that may not be fully utilized by each employee, a flex program ensures that benefit coverage is directed at those elements that will be most utilized and most valued, according to individual need and circumstance.

20. Design features within the plan include cost-containment elements intended to moderate cost escalations. Employee co-payments, fee caps, reimbursement maximums and least-cost-alternative drug coverage are some of the features embedded into the design that provides cost-management support.

21. Enbridge has two retiree benefit plans, based on eligibility. Both are funded by the Company. The plans offer either a traditional benefit plan based on reimbursement for prescription costs incurred, or a health spending account. Both plans have a maximum payout, dispensing fee caps, and lifetime maximums.

22. Enbridge offers two pension plan options – Defined Benefit ("DB") and Defined Contribution ("DC") plans within the Enbridge registered pension plan.

23. Costs to provide employees with retirement planning and pension education sessions to address our fiduciary responsibility to ensure their ability to make informed pension choices are also included within the pension expense category.

24. Pension costs increase by $17.3 million in 2012 and $7.1million in 2013. An explanation for each year is outlined as follows:

(1) 2012 pension costs increase by $17.3 million from 2011 Historical. This increase is primarily due to the funded status of the plan going from a surplus position to a deficit position where the plan surplus or deficit is the net position when comparing the fair-value of the plan assets against the actuarial assessment of the plan obligations as at a given date. An excess of plan assets over plan obligations results in a surplus, while the reverse results in a deficit. Due to the pension plan expected to be in a deficit position, Enbridge is required to fund the pension plan for an

amount that represents annual employee current service costs. As such the increase from 2011 is primarily employee current service costs as a result of pension regulations requiring plan sponsors to fund pension plans should the plan be in a deficit position. Please refer to EB-2011-0277, Exhibit B, Tab 2, Schedule 6, for details on the funded status, filing requirements, and the impact to the Company; and

(2) 2013 pension expenses have increased $7.1 million from the 2012 Estimate. This increase is due to the plans expected deficit position at the end of 2011 requiring contributions. These contributions represent current employee service costs as well as contributions starting in 2013 required to bring the plan from a deficit position to a surplus position. The 2012 pension expenses represent expenses under a cash basis whereas 2013 pension expense represents pension expense under an accrual basis of accounting under US Generally Accepted Accounting Principles (USGAAP). The increase however has no bearing on the fact that two different basis of expense are being used. Regardless of cash or accrual basis of expense Enbridge will incur an increase from 2012 to 2013 and in fact USGAAP provides for a smaller increase over 2012 compared to a cash basis. For a full analysis of cash versus accrual basis of pension expense please refer to EB-2011-0354, Exhibit A2, Tab 3, Schedule 2.

Employee Development

25. A fundamental component in effectively managing the transition to replace retiring workers is the need to support their training and development. Ensuring a smooth transition without incurring major skill gaps require technical and business training and an investment in leadership development.

26. The Company has always had a strong focus on providing developmental opportunities to support skills development and enhancement. This is a critical lever in being able to attract and retain the talent that the Company needs to maintain the business and provide service to the customers.

27. Enbridge continues to focus on delivering quality developmental programs in a cost-effective manner. The Company continues to make improvements in course development and administration focusing on providing employees with leadership development programs, general skills curriculum, tuition aid, and mentoring programs. The Training and Development budget remains constant at $2.1 million.

28. A strong focus continues to be placed upon performance management, ensuring employees performance is linked to objectives and desired outcome to drive efficiencies and productivity. As such, $2 million has been established for severances in the 2013 Budget, which allows for both severances and additional compensation where necessary.

29. A table of all Employee Expenses below outlines particular expenses that apply to Enbridge in the 2013 Budget, 2012 estimate, and the 2011 Historic. The benefits and pension expense exceed inflation rates due to the increase in number of employees, the cumulative impact of salaries and benefits increasing at a rate higher than inflation due to demographics and the costs demands by benefits suppliers. In addition, the pension deficit contributes significantly to the budget in 2012 and 2013. This deficit is simply a function of prevailing market conditions all of which are beyond the control of the Company. The increase in staffing levels is determined on the basis of need by departmental managers. These requests are then reviewed by the Executive Management Team and, where justification exists, the additional staffing levels are approved.

Table 1

Major Employee Expenses
2013 Budget, 2012 Estimate, 2011 Historic

Line No.	Particulars ($ 000's)	2013 Budget	2012 Estimate	2011 Historic
		$	$	$
1	Salaries and Wages	185,988	176,550	158,061
2	Short Term Incentive Pay	20,257	19,428	22,272
3	Benefits	30,452	25,941	23,193
4	Pension	27,704	20,557	3,224
5	Training and Development	2,610	2,610	2,610
6	Awards and Allowances	1,302	1,302	1,302
7	Relocation	500	500	500
8	Severances	2,000	1,000	1,980
9	FTE’s	2,287	2,231	2,070

Updated Evidence

30. 2011 Actual Salaries and Wages was $155.4 million compared the original filed amount of $158.1 million. The $2.7 million represents 1.7% of the original amount. This lower salaries and wages is the result of vacancies during the historic year.

31. 2011 Actual Short Term Incentives paid was $26.0 million compared the 2011 Historic of $22.3, an increase of $3.7 million. The increase in STIP payout is the result of improved financial performance in comparison to original estimates and higher levels of employee performance recognized at year end.

32. 2011 Actual Benefits expense was $24,263 million compared the 2011 Historic of $23,193 as originally filed. The $1.1 million increase was from increased medical and dental claims by employees.

33. 2011 Actual Relocation expenses were $2.3 million compared to the 2011 Historic estimate of $0.5 million as originally filed. This increase is the result of having to relocation a higher number of employees, including several senior EMT members. The relocations were a result of succession planning with a focus on leadership development to ensure the future success of the Company.

UPDATED CORPORATE COST ALLOCATION

Executive Summary

1. The purpose of this evidence is to update the Board with respect to further developments since the time the original prefiled evidence was filed at Exhibit D1, Tab 4, Schedule 1 on January 31, 2012, specifically:
   - Renewal of the Inter-corporate Services Agreement (“ISA”) with Enbridge Inc. effective January 1, 2011;
   - RCAM updated results for the years 2012 and 2013;
   - Updated RCAM study undertaken by MNP LLP (“MNP”); and
   - The Company’s response to the proposals made by MNP in its 2013 report.

Renewal of the Inter-corporate Services Agreement with Enbridge Inc.

2. The Company has an agreement in place with respect to the renewal of its ISA with Enbridge Inc. for a further period of five years commencing January 1, 2011.

3. Changes were made to the January 1, 2006 ISA (that expired on December 31, 2010) in order to update processes related to information exchange, payment and dispute resolution. These revisions were shared with intervenors prior to finalizing the renewal agreement and were discussed at the 2011 and 2012 RCAM Consultative review meetings held on January 31, 2012 and May 2, 2012, respectively.

4. The renewed ISA, dated January 1, 2011, has been executed and a complete copy of the ISA and its attachments is provided in Attachment 1.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

Updated RCAM Results for the Years 2012 and 2013

5. The RCAM methodology, as last approved by the Board in EB-2006-0034, has been consistently applied throughout the incentive rate regulation period starting in 2008. The Board-approved RCAM methodology has resulted in 2012 and 2013 allocation amounts to EGD of $31.8 million and $32.3 million respectively, which were submitted to MNP for review and assessment as part of its updated 2013 RCAM study.

6. In accordance with the Supplementary Settlement Agreement accepted by the Board during the second phase of EGD's 2007 rate application hearing, the Company has continued the corporate cost allocation consultative for the 2008-2012 Incentive Rate Regulation period, as agreed.

7. In this regard, for each of the years 2008 – 2012 inclusive, the Company has, on a regular basis, provided the RCAM consultative group members with certain information, as set out in the RCAM Supplementary Settlement Proposal of September 27, 2007. This includes an explanation of the cost drivers for any significant year-over-year increases in RCAM amounts. Most recently, an RCAM Consultative meeting was held on January 31, 2012, in part, to review the 2011 results and provide an update in respect of 2012. On May 2, 2012, another RCAM Consultative meeting was held, again in part, to review the 2012 results and the updated forecast for 2013.

8. An updated summary table setting out the costs allocated to the Company for each primary service, general expense and direct charge for each of the years from 2007 to 2013, as calculated using the Board-approved RCAM methodology prior to any MNP proposed downward adjustment, is provided in Attachment 2.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

MNP's Updated (2013) RCAM Study

9. In the June 28, 2011 Settlement Agreement in respect of the 2010 Earnings Sharing Mechanism proceeding, EB-2011-0008, it was agreed that the Company would, in support of its 2013 rates application, file an updated study addressing the costs sought to be recoverable under the RCAM for future years (2013 and beyond).

10. The Company engaged MNP to conduct an independent review of Enbridge's RCAM, and assess the reasonableness and appropriateness of corporate service charges calculated by the RCAM for 2012 and 2013. The foundational framework for this assessment is the Board's Three Prong Test.[1]

11. The scope of MNP's role as independent reviewer included receiving and reasonably considering the comments of RCAM Consultative members prior to finalizing its report. To this end, the following key steps were taken:

- an RCAM Consultative meeting was held on January 31, 2012, to provide the intervenors an opportunity to speak with MNP while it was in the early stages of undertaking its review and analysis. Additional work has been undertaken by MNP in response to suggestions and requests made by the intervenors;
- MNP's draft report was circulated to the Consultative prior to its issuance in final form; and
- a meeting was held on May 2, 2012 where MNP invited, received and subsequently considered comments received from intervenors prior to finalizing its report.

[1] See MNP's Final Report dated May 17, 2012, pages 1, 5-6, 48 and Appendix A for description of the scope of work.

12. The product of this work is a final report prepared by MNP entitled: "Independent Evaluation of the 2013 Regulatory Cost Allocation Methodology Results" plus Appendix dated May 17, 2012, filed at Exhibit D2, Tab 1, Schedule 1.

Conclusion

13. By its engagement of MNP as an independent reviewer and the involvement of the RCAM Consultative in MNP's review process, the Company submits that it has fully satisfied the requirements of the EB-2011-0008 Settlement Agreement. MNP's independent review of the results of the 2012 and 2013 RCAM-generated results lead to its general conclusion that these allocations are being incurred prudently and allocated appropriately with benefits that exceed costs for ratepayers[2].

14. Given MNP's findings that the RCAM methodology continues to meet all regulatory requirements, subject to the valuation/cost adjustments made by MNP[3], the Company has accepted MNP's proposed RCAM amount of $31.6 million for 2012 for the purpose of determining the 2012 earnings sharing mechanism. As well, the Company has adopted the $32.1 million MNP proposed RCAM amount for inclusion in the 2013 test year cost of service and is seeking the Board's approval for recovery from ratepayers of this amount in 2013 rates.

15. The Company notes that MNP, in addition to its proposed valuation/cost adjustments which have already been accepted, has made a number of RCAM process improvement recommendations for consideration by the Company going forward.[4] The Company also notes that certain of MNP's current RCAM process

[2] MNP Final Report dated May 17, 2012, page 2.
[3] With the three failed Prong Three Tests (Capital Market Financing & Access, Employee Development, HRIS Program Management and Development), MNP proposes a consolidated downward adjustment to 2012 and 2013 RCAM allocations of $154,923 and $158,329, respectively.
[4] MNP Final Report dated May 17, 2012, pages 2 and 52-53.

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

improvement recommendations are materially similar to certain recommendations from MNP's 2007 Report.[5]

17. While the Company appreciates that it may be appropriate to consider practical refinements to the RCAM methodology over time, in light of MNP's findings, the Company does not believe that fundamental changes to the RCAM methodology are warranted or appropriate for consideration in this proceeding. The Company is, however, prepared to work with MNP to consider in greater detail those recommendations, such as the functional roll up of services, over the balance of 2012 with a view to filing any request for change in the Company's next rates proceeding.

[5] For example, functional roll up of services and adoption of formal performance management process.

INTERCORPORATE SERVICES AGREEMENT

THIS AGREEMENT made as of the first day of January, 2011

BETWEEN:

ENBRIDGE INC., a corporation incorporated under the laws of Canada (the "**Service Provider**")

- and -

ENBRIDGE GAS DISTRIBUTION INC., a corporation incorporated under the laws of the Province of Ontario (the "**Service Recipient**")

WHEREAS the above-named parties ("**Parties**") entered into a prior intercorporate services agreement made as of January 1, 2006 (the "**Prior Agreement**");

AND WHEREAS the Affiliate Relationships Code for Gas Utilities rule (the "Code") of the Ontario Energy Board ("**OEB**") prohibits the term of an intercompany services agreement to be greater than five (5) years without OEB approval;

AND WHEREAS the Parties wish to continue the relationship set out in the Prior Agreement whereby the Service Provider provides services to the Service Recipient, in accordance with the terms and conditions of this agreement, and any attached schedules (the "**Agreement**").

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and mutual covenants hereinafter contained, the Parties agree:

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1. Termination of Prior Agreement

Effective as of 11:59 pm EST on December 31, 2010, the Prior Agreement is terminated. Effective as of 12:00 am EST on January 1, 2011 this Agreement shall be in full force and effect.

2. Regulatory Considerations

The Parties acknowledge that this Agreement shall be subject to any rule or order applicable to the Service Recipient made by the OEB pursuant to the Ontario Energy Board Act, S.O. 1998, c. 15, Sch. B., s. 44, including without limitation, the Code, as amended from time to time. The Service Provider agrees to do such things as are reasonably necessary to assist the Service Recipient in complying with these rules, including without limitation:

(a) to comply promptly with all requests either made or authorized by the OEB for information with respect to:

  (i) the Services; and

  (ii) the cost to the Service Provider of providing the Services; and

(b) to include equivalent provisions to those set out in this section in any contracts the Service Provider enters into with another of its affiliates for the purpose of providing any service, resource or product used in the provision of the Services.

3. Regulatory Cost Allocation Methodology

The Parties have developed a regulatory cost allocation methodology (**"RCAM"**), attached hereto as Schedule 1, that has been reviewed and approved by the OEB and may be amended from time to time. RCAM sets out the purpose, objectives, principles, and procedures underlying the identification and costing of the Services for the purpose of determining the amounts which the Service Recipient will request to be recovered in rates from time to time. Where a section of this Agreement is inconsistent with RCAM, RCAM shall prevail to the extent of the inconsistency.

4. Services and Allocation Bases

The Parties shall develop a schedule to describe each individual Service (**"Service Schedules"**), and the applicable quantity and quality indicators, to be provided in any given year. The Services may be comprised of one or more of the following components, as described in further detail in RCAM:

a) **Primary Services:** defined as a service provided by the Service Provider to the Service Recipient either as the sole provider or as a supplemental provider (where the Service Recipient performs a component of the required activities of the service). A list of the primary services and the bases of allocation attributable thereto, are set out in RCAM.

b) **Support Services:** defined as a service provided by the Service Provider that is necessary to support a primary service to the Service Recipient. Support services are further classified as infrastructural, content, or resource support services, and are listed in RCAM with the applicable allocator.

c) **General Expenses:** defined as a significant cost that benefits the Service Recipient, and requires allocation on a basis separate from a primary service because the driver of the cost is different, or because the cost is a large, third party cost. A list of the general expenses and the basis of allocation attributable thereto, are set out in RCAM.

d) **Direct Charges:** defined as a general expense for services that can be externally priced and specifically attributed to the Service Recipient without loading. A list of the direct charges and the basis of allocation attributable thereto, are set out in RCAM.

e) **Department Costs:** defined as all direct employee and employee-related costs, plus general expenses related to the department, that relate to the primary services and support services.

f) **Return on Invested Capital:** defined as a charge for the Service Recipient's share of the weighted average cost of capital applied to the net book value of property, plant and equipment used to deliver the services. The return on invested capital shall be no higher than the Service Recipient's weighted average cost of capital as approved by the OEB from time to time.

5. Allocation Procedures

Cost allocations shall be made in accordance with the processes and procedures documented in RCAM, which describes how primary services are fully-burdened with department costs, direct charges, general expenses, support services (also fully burdened), and a return on invested capital before being allocated to the Service Provider.

The Service Provider, in consultation with the Service Recipient, shall set the RCAM cost allocations for the Services prior to December 31 each year, or as soon thereafter that the Parties can conclude the relevant budgeting and cost allocation processes, and in any event, prior to March 31 of the year to which the RCAM cost allocations are applicable. The Parties shall execute a confirmation notice ("**RCAM Confirmation Notice**") and Service Schedules to evidence the Parties' agreement to the RCAM cost allocations for that year, which shall be incorporated into and form part of this Agreement. A copy of the pro forma RCAM Confirmation Notice is attached hereto as Schedule 2, and the executed RCAM Confirmation Notice shall become Schedule 2(a) for 2011, Schedule 2(b) for 2012, and so on.

The RCAM cost allocations shall not be amended within the year to which they apply, except in accordance with section 7 below.

In addition to the determination of the RCAM cost allocations, the Service Provider shall develop cost allocations applicable to the Service Recipient pursuant to an alternate corporate cost allocation methodology (**"CAM"**) that is not approved by the OEB. The Service Provider shall determine and apply the CAM cost allocations in accordance with the CAM policies and procedures developed by the Service Provider from time to time.

6. Payment Procedures

The following sets forth the procedure applicable to payments related to Services delivered hereunder:

a) The Service Provider shall prepare monthly recurring journal entries to one or more accounts of the Service Recipient based upon the CAM cost allocations and provide an annual CAM report to the Service Recipient at least thirty (30) days prior to the beginning of the calendar year to which the journal entries relate, or as soon thereafter as reasonably practicable, as a payment notice (**"Payment Notice"**) to the Service Recipient.

b) The Service Recipient shall notify the Service Provider immediately of any inaccuracy in each Payment Notice, and failing resolution, the Parties shall endeavor to resolve the dispute in accordance with the dispute resolution mechanism set out in section 15 below.

c) The Service Recipient shall pay the amounts indicated in each Payment Notice on or before the end of each calendar quarter to which the Payment Notice relates, or if there is a dispute about the amount, within thirty (30) days of the date that an amount has been determined by the dispute resolution mechanism. The Service Provider shall apply any payments made hereunder to and in satisfaction of both the CAM and RCAM cost allocations owing.

d) All amounts payable under this Agreement are expressed, and shall be paid, in Canadian dollars unless otherwise stated in the Payment Notices.

e) In the event that the Minister of National Revenue for Canada or any other competent authority at any time proposes to issue or does issue any assessment or assessments that impose or would impose any liability for tax of any nature or kind whatsoever on the Service Provider or the Service Recipient on the basis that the fair market value of any of the services is different than the amount charged by the Service Provider for the corresponding Services (the "**Services Charge**"), and in the event that the Parties agree that the fair market value of the services is different than the Services Charge, then upon such agreement the Services Charge that the Service Recipient is obligated to pay for the said services shall be varied by increasing or decreasing the amount of the Services Charge as the Service Recipient and the Service Provider may agree.

7. Service Agreement Review and Amendment Process

This Agreement and any related Service Schedules may be amended from time to time upon the approval in writing of the Parties. Version control and archival storage of all amendments shall be the responsibility of the Service Recipient.

8. Term and Termination

8.1 Subject to section 8.3 below, this Agreement shall be effective January 1, 2011, and terminate December 31, 2015 (the "**Term**").

8.2 Each Service Schedule shall have an initial term of one year commencing January 1, 2011 and be automatically renewed for subsequent periods of one year until the end of the Term, subject to any service adjustments agreed to by the Parties in accordance with this Agreement.

8.3 The Parties may terminate this Agreement by mutual consent, in writing, except that the Service Recipient shall have the right to terminate this Agreement immediately in the event that it ceases to be a direct or indirect wholly owned subsidiary of the Service Provider.

9. Indemnification

Each of the Parties (the "**Indemnifier**") shall indemnify and hold the other Party (the "**Indemnified Party**") harmless from and against any loss, damage, claim, liability, debt, obligation or expense (including reasonable legal fees and disbursements) incurred or suffered by the Indemnified Party caused by the Indemnifier, and relating in any way to this Agreement or the provision of the services, including any loss, damage, claim, liability, debt, obligation or expense resulting from or arising from or in connection with a negligent act or negligent omission of the Indemnifier.

10. Confidential Information and Personal Information

Each of the parties hereto agrees to keep all information provided by the other party (the "**disclosing party**") to it (the "**receiving party**") that the disclosing party designates as confidential or which ought to be considered as confidential from its nature or from the circumstances surrounding its disclosure ("**Confidential Information**") confidential, and a receiving party shall not, without the prior consent of an authorized senior officer of the disclosing party, disclose any part of such Confidential Information which is not available in the public domain from public or published information or sources except:

a) to those of its employees who require access to the Confidential Information in connection with performance of Services hereunder;

b) as in the receiving party's judgement may be appropriate to be disclosed in connection with the provision by the receiving party of Services hereunder;

c) as the receiving party may be required to disclose in connection with the preparation by the receiving party or any of its direct or indirect holding companies, affiliates or subsidiaries of reporting documents including, but not limited to, annual financial statements, annual reports and any filings or disclosure required by statute, regulation or order of a regulatory authority; and

d) to such legal and accounting advisors, valuators and other experts as in the receiving party's judgement may be appropriate or necessary in order to permit the receiving party to rely on the services of such persons in carrying out the receiving party's duties under this Agreement.

The covenants and agreements of the parties relating to Confidential Information shall not apply to any information:

a) which is lawfully in the receiving party's possession or the possession of its professional advisors or its personnel, as the case may be, at the time of disclosure and which was not acquired directly or indirectly from the disclosing party;

b) which is at the time of disclosure in, or after disclosure falls into, the public domain through no fault of the receiving party or its personnel;

c) which, subsequent to disclosure by the disclosing party, is received by the receiving party from a third party who, insofar as is known to the receiving party, is lawfully in possession of such information and not in breach of any contractual, legal or fiduciary obligation to the disclosing party and who has not required the receiving party to refrain from disclosing such information to others; or

d) disclosure of which the receiving party reasonably deems necessary to comply with any legal or regulatory obligation which the receiving party believes in good faith it has.

If in the course of performing services, the receiving party obtains or accesses personal information about an individual, including without limitation, a customer, potential customer or employee or contractor of the disclosing party ("Personal Information") the receiving party agrees to treat such Personal Information in compliance with all applicable federal or provincial privacy or protection of personal information laws and to use such Personal Information only for purposes of providing the services. Furthermore, the receiving party acknowledges and agrees that it will:

a) not otherwise copy, retain, use, modify, manipulate, disclose or make available any Personal Information, except as permitted by applicable law;

b) establish or maintain in place appropriate policies and procedures to protect Personal Information from unauthorized collection, use or disclosure; and

c) implement such policies and procedures thoroughly and effectively.

The Service Recipient shall be entitled periodically to conduct reviews of the procedures implemented by the Service Provider in relation to the obligations described in this Section 10.

Upon the termination of the provision of the services each party shall immediately return to the other party all Confidential Information and Personal Information provided by the disclosing party to the receiving party, and all copies thereof in its possession or control (other than such Confidential Information or Personal Information which continues to be used or relevant to the provision of the services), or destroy such information and copies and certify to the disclosing party that such destruction has been carried out.

11. Audit Rights

The Service Recipient shall have the right, at its own cost and by notice to the Service Provider at reasonable hours to examine and make copies of the books, records and charts of the Service Provider to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to any of the provisions of this Agreement and to comply with any government filing requirements. Such books, records and charts shall be preserved in accordance with the records retention policies of the Service Provider, provided the books, records or charts related to any matter disputed between the Parties or which is the subject of an outstanding application or proceeding before a government body shall be preserved until such dispute is settled or such application or proceeding has been finally resolved, whichever is later. The Service Recipient's rights under this Section to view books, records and charts to make copies:

(a) for internal purposes, shall subsist for a period of two (2) years from the end of the calendar year to which such books, records and charts relate, both during the term of this Agreement and for a period of two (2) years after expiration or termination of this Agreement, and

(b) for the purposes of complying with the requirements of governmental bodies, including tax authorities, shall subsist for a period of seven (7) years from the end of the calendar year to which such books, records and charts relate, both during the term of the Agreement and for a period of two (2) years after expiration or termination of this Agreement.

If this Agreement has been terminated or has expired, the Service Provider's obligations to preserve such books, records and charts in accordance with its records retention policy shall continue. The Service Provider may fulfill such obligations by continuing to preserve such books, records, and charts or by delivering them to the Service Recipient.

12. Force Majeure

If either Party is rendered unable by force majeure to carry out its obligations under this Agreement, other than a Party's obligation to make payments to the other Party, that Party shall give the other Party prompt written notice of the event giving rise to force majeure with reasonably full particulars concerning it. Thereupon, the obligations of the Party giving the notice, so far as they are affected by the force majeure, shall be suspended during, but no longer than the continuance of, the force majeure. The affected Party shall use all reasonable diligence to remove or remedy the force majeure situation as quickly as practicable.

13. Quantity and Quality of Service

Quantity and quality indicators are included in each Service Schedule appended to the applicable RCAM Confirmation Notice for the year in which the related service is provided. In accordance with section 14 below, the Parties shall review and update the Service Schedules and the RCAM in each year that services are being provided prior to signing the RCAM Confirmation Notice, to ensure quantity and quality indicators are accurately reflected.

The Service Provider shall perform the services in accordance with the Service Schedules, and shall use reasonable efforts to perform the services in accordance with any additional instructions received from the Service Recipient at any time during a year; provided, however, that the Service Provider shall not be required to incur any additional costs related to the request.

14. Performance Reviews

The Parties will conduct performance review meetings annually, at least four months prior to the end of each year in the Term, between personnel of the Service Recipient who receive the services, and personnel of the Service Provider who provide the services. The purpose of these meetings is to assess and report upon whether the services are being delivered in accordance with the Agreement. Any changes to the operating environments, to the extent that they impact, or could impact, service delivery in any way shall be identified, discussed and monitored.

Personnel conducting the performance review meetings shall provide formal written confirmation whether the services are being delivered in accordance with the Agreement (based on the services descriptions and the quality and quantity indicators in the Service Schedules), and a description of any negotiated changes to the services as a result of this review, to each of the Controller's Groups of the Service Provider and Service Recipient prior to October 1 in the year to which the performance review relates. The Parties shall include all negotiated changes in the updates made to the Service Schedules and the RCAM for the following year in which services are provided.

15. Dispute Resolution Process

In the event that the applicable managers of the Parties cannot resolve an issue related to the nature or performance of services, the amount or bases of the cost allocations, or the interpretation of the Agreement within ten (10) business days of the date that written notice of the disputed issue is received by the non-disputing Party from the disputing Party, then either Party may send a written notice of the dispute to the responsible executives to be escalated upward through the respective organizations of the Parties, to Director, Vice-President and/or President, for resolution within twenty-one (21) business days after the receipt by the applicable executive of the notice. If required, the President of the Service Recipient shall make a final determination. The Director of each of the Parties' Controller's Groups shall facilitate this dispute resolution process and ensure that any negotiated changes resulting from the performance review process be incorporated into the updates made to the Service Schedules and the RCAM for the following year in which the Services are provided.

Upon mutual agreement of the Parties, any dispute or issue of interpretation arising hereunder may be jointly referred for non-binding guidance or arbitration to an external facilitator with recognized expertise in the subject matter of the dispute or issue of interpretation.

16. General

The Service Recipient shall be responsible for and shall pay all applicable federal, provincial, municipal goods and services taxes arising from the provision of Services hereunder, including provincial sales tax if applicable.

A Party shall, from time to time, and at all times, do such further acts and execute and deliver all such further deeds and documents as shall be reasonably requested by the other Party in order to fully perform and carry out the terms of this Agreement.

Any notice, request, demand, direction or other communication required or permitted to be given or made under this Agreement to a Party shall be in writing and may be given by hand delivery to the Party to whom it is addressed or sent by facsimile or electronic mail to such party at its address noted below or at such other address of which notice may have been given by such Party in accordance with the provisions of this section.

Service Provider:	Enbridge Inc.
Address:	#3000, 425 – 1st St. S.W. Calgary, AB T2P 3L8
Attention:	Senior Vice President & Controller
Email:	john.whelen@enbridge.com
Facsimile:	403-231-3944
Service Recipient:	Enbridge Gas Distribution Inc.
Address:	500 Consumers Road North York, ON M2J 1P8
Attention:	Vice President, Finance
Email:	narin.kisinchandani@enbridge.com
Facsimile:	416-495-5998

Any such facsimile or electronic mail shall be deemed to have been received at the opening of business at the premises of such addressee on the first business day following the transmission of such notice.

This Agreement may be executed in counterparts, no one of which needs to be executed by both of the Parties. Each counterpart, including an electronic transmission of this Agreement, shall be deemed to be an original and shall have the same force and effect as an original. All counterparts together shall constitute one and the same instrument.

This Agreement will enure to the benefit of and be binding upon the Parties thereto and their respective successors. This Agreement may not be assigned by either of the Parties thereto without the prior written consent of the other.

The division of this Agreement into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder", and similar expressions refer to this Agreement and not to any particular section or other portion hereof. Unless something in the subject matter or context is inconsistent therewith, references herein to articles and sections are to articles and sections of this Agreement. Words importing the singular number shall include the plural and vice versa, words importing the masculine gender shall include the feminine and neuter genders and vice versa, and words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and vice versa.

In the event that one or more of the provisions contained in this Agreement shall be invalid, illegal or unenforceable in any respect under any applicable law, the validity, legality or enforceability of the remaining provisions hereof shall not be affected or impaired thereby. Each of the provisions of this Agreement is hereby declared to be separate and distinct.

This Agreement constitutes the whole and entire agreement between the Parties respecting the subject matter of the Agreement and supersedes any prior agreement, undertaking, declarations, commitments, representations, verbal or oral, in respect thereof.

ENBRIDGE INC.

Per: ______________________
J.K. WHELEN - SENIOR VP & CONTROLER

Per: ______________________
J.R. BIRD - EXECUTING VP, CHIEF FINANCIAL OFFICER & CORPORATE DEVELOPMENT

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM
ENBRIDGE LAW
TP

Per: ______________________ D. Guy Jarvis
President

Per: ______________________ Mark R. Boyce
Vice President, Law & Information Technology

ENB LL 24510800

ENBRIDGE™

Regulatory Cost Allocation Methodology

1 PURPOSE

The Regulatory Cost Allocation Methodology ("RCAM") has been developed to determine the allocation of costs from Enbridge Inc. ("EI") to Enbridge Gas Distribution Inc. ("EGD"). The outputs of RCAM are intended to be an input to the rate filings submitted to the Ontario Energy Board ("OEB"). The methodology has been developed by application of sound costing principles and regulatory precedents and has specifically been aligned with the Affiliate Relationship Code for Gas Utilities, originally issued on July 31, 1999 and as amended from time to time (the "ARC").

This RCAM, however, does not replace the existing Corporate Cost Allocation Methodology ("CAM") which will still be used by EI to transfer costs to all its affiliates, including EGD, for internal management and performance measurement purposes.

1.1 About Enbridge

EI is a leader in energy transportation and distribution in North America and internationally. EI operates the world's longest crude oil and liquids transportation pipeline and Canada's largest gas distribution company. EI also operates natural gas transmission pipelines and midstream businesses in the United States and invests in international energy projects. EI's activities are comprised of regulated and non-regulated businesses. The transportation and distribution activities are regulated by the National Energy Board, the OEB, the Federal Energy Regulatory Commission and various provincial and state regulators.

1.2 Need for a Corporate Cost Allocation Methodology

EI's perspective is that an "integrated" operating model reflects the fact that the corporate office is effectively managed as an integral extension of the decision making and operating activities of its business units and affiliates (for the benefit of the business units and affiliates), rather than as a passive "Holding Company" which merely manages a portfolio of investments (for the benefit of the Holding Company shareholders). The impact of this operating model will result in a decreased overall cost of each respective affiliate's operating and maintenance expenses due primarily to the potential for economies of scale. As various functions shift from an affiliate to the Corporate Shared Service Centre the associated cost will be expected to decrease. The resulting corporate cost allocations back to the affiliate would be offset by this reduction in their own incurred costs. For management purposes, these operating costs and benefits need to be tracked.

1.3 Need for a Regulatory Corporate Cost Allocation Methodology

EI recognizes that the objectives of a cost allocation methodology established for internal management and performance measurement purposes may differ from the objectives of a cost allocation methodology established to meet the needs of a regulator, mandated to protect the interests of various rate paying groups.

In recognition of the needs of the regulator, EI has developed the RCAM with the objective of meeting the regulatory requirements of the OEB (as set out in ARC, OEB decisions, and as reflected in industry).

2 DESIGN OBJECTIVES AND PRINCIPLES

The objective of the RCAM is to establish, in the context of Ontario regulation and OEB precedents, the appropriate charges to be allocated for services delivered by EI to EGD in a given fiscal period. These charges are intended to be included in EGD's rate filings.

The methodology will be service based, focused on the needs of EGD and its usage of the services, understandable and transparent, rigorous and practical to administer and supported by verifiable data and records wherever practicable.

2.1 Regulatory Design Principles

Regulators must review and set rates in accordance with their empowering legislation. However, the legislation seldom contains specific guidance on how to set rates. As a result, regulators frequently refer to established regulatory principles to guide their judgment. These key principles include:

- just and reasonable,
- cost of service; and
- prudence.

Just and Reasonable
The primary regulatory principle, and the one most likely to be incorporated into regulatory legislation, is that rates should be "just and reasonable". "Just and reasonable" applies to both customers and regulated entities. It requires a weighting of the legitimate interests of both parties.

Cost of Service
Under this principle, a regulated entity is permitted to set rates that allow it the opportunity to recover its costs for regulated operations, including a fair rate of return on its investment devoted to regulated operations – no more, no less.

This principle is consistent with what is expected to occur in a competitive market, where the price of services tend towards the cost of providing them, including a fair return- a principle that has been recognized by the OEB:

> *The Board notes that the general role of the regulator is to act as a proxy for competition. In pricing services in a competitive market the relevant costs would be the costs incurred by the service provider in providing the service, plus an appropriate return in order to attract the capital necessary to provide the service.*[1]

It is important to note that this standard only gives the entity the opportunity to earn a fair return; it does not guarantee it. In most cases, rates are set prospectively, based on anticipated future costs. If the entity over-recovers, it usually keeps the excess. If it under-recovers, it bears the deficiency.

The 'cost of service' principle reflects the need for fairness and the necessity to offer adequate incentives for providing regulated services. That is:

- an entity's investors should have the opportunity to recover their costs, including a fair return, just as they would if they were to invest in a non-regulated entity of similar risk.

[1] OEB; RP-2001-0032; Enbridge Consumers Gas Distribution Inc.; December 13, 2002; Sec. 5.11.49.

However, customers should not have to provide investors with the opportunity to earn more than they could expect from investing in non-regulated operations.

- from an incentive viewpoint, unless investors have a reasonable opportunity to recover their costs, it will be difficult to attract the investment necessary to provide regulated operations. However, the opportunity to recover costs, including a fair return, should provide an adequate incentive to attract those funds.

Prudence

The prudence standard modifies the "cost of service" standard. Under this standard, customers should be charged only for prudently incurred costs. This recognizes a regulated entity's responsibility to manage itself in a prudent manner and provide regulated services at the most efficient cost.

Prudence is established by determining what a reasonable person would have done in a similar situation. This should not be done while making use of hindsight. A regulated entity's management can be expected to rely only on information reasonably available to it when it makes its decision.

Normally, there is a presumption of management prudence. However, the OEB has stated that this presumption will not apply to transactions between affiliates:

> *… when transactions occur between or among affiliates, the Board will not presume prudence and the onus is on the utility to establish, to the satisfaction of the Board, that the transaction is prudent and that the corresponding costs to the utility associated with the transactions are fair.*[2]

This reflects the potential conflict of interest with such transactions. As a result, regulated utilities must provide adequate support for their intercorporate charges.

In this regard, the OEB has identified what it has referred to as the "three prong test" for Corporate cost allocations, whereby a utility must demonstrate that the charges meet three tests:

- Cost Incurrence - are the proposed charges prudently incurred by, or on behalf of, the utility for the provision of a service required by Ontario ratepayers – i.e., would the utility have incurred the cost if it were operating as a stand-alone utility?,
- Cost allocation - if properly incurred, are the proposed charges allocated appropriately to the utility, based on the application of cost allocation factors and supported by principles of cost causality?; and
- Cost/Benefit - do the benefits to the utility's Ontario ratepayers equal or exceed the costs?

In meeting the third test – Cost/Benefit – the OEB has stated that it would accept four categories of support as a basis for assessing quantifiable benefits:

- Replacement benefits- the services provided replace an equivalent service at equal or lower cost,
- Synergistic or linkage benefits - the services allow the utility to reduce costs by means of being part of a larger organization and operating in concert for the procurement of products and services,
- Revenue enhancement or cost recovery benefits - the utility's activities and capabilities provide value to other affiliates for which payment in cash or kind is received; and

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[2] OEB; RP-2001-0032; Enbridge Consumers Gas Distribution Inc.; December 13, 2001; Sec. 5.11.30.

- Stand-alone benefits- strategic actions and activities instituted by affiliates that produce direct value to the utility.

2.2 Budget-Based Allocations

As EGD's rates are ultimately based upon a cost of service or rebasing proceeding which uses forward year cost estimates, it is appropriate to similarly use EI's estimated costs, namely its Budget, for the RCAM.
. At EI, the budget process is rigorous and the budget is the primary tool managers use for cost control (i.e., the budget process is primarily used to control costs and not the allocation process).

Enbridge budgets costs in three categories based on the notion of grouping cost types:

Department Costs: specific employee and service related costs
General Costs: costs that support several or all business units, but do not relate to one specific affiliate
Direct Costs: costs specifically identifiable to an affiliate

2.3 Regulatory Driven Design Features

Based on regulatory principles and precedents, four key design principles were included in the RCAM design.

- Services Based Approach
- Multi-Step Allocation Process
- Service Description Transparency
- Demand Pull by Recipients

2.3.1 Service Based Approach

The core design principle for the RCAM is the adoption of a service based approach for allocation as required by the OEB and the ARC. The OEB's application of the three-prong test is designed to be applied to service based allocations:

- A utility must demonstrate that all the services associated with the corporate cost allocations are necessary, not just some of the services from a department that charges to the utility or even the majority of the services from a department.
- Where a department supports more than one service and each service has a different causal relationship to affiliates, the services must be broken out so that the most appropriate allocation can de developed for each service provided by that department.
- Cost benefit will be evaluated (wherever possible) by individual service, which requirement is to be discretely defended.

The implication is that each service is fully-burdened with all the costs incurred in delivery. The services costs will therefore include allocations from all applicable department, general and direct budgets. In addition, in some cases certain services may also provide infrastructural or content support to the delivery of other services.

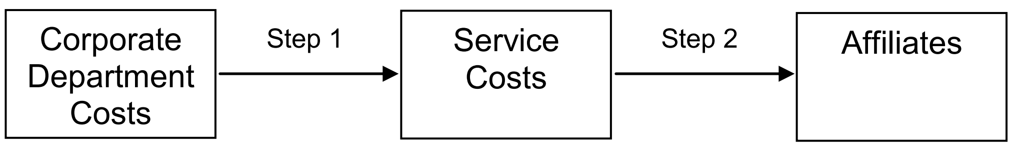
2.3.2 Multi-Step Allocation Process

Using a (fully burdened) service based costing approach also implies that a multi-step allocation process is required. The costs are budgeted at the department level and allocated to each service provided prior to allocation of the fully burdened service cost to the affiliate using the services. Described in its simplest form, the RCAM utilizes a two (composite) step costing approach (See Section 3 for details).

Step 1: At EI, as at most organizations, costs are collected and budgeted in cost centers or departments. Each department offers one or more services. The pool of departmental costs must firstly be allocated to the services provided by the department.

Step 2: Once the services of the department have been costed, a proportion of the cost that represents the actual usage by the affiliate is then allocated to that affiliate.

Figure 1: Two (composite *) Step Allocation Process



* In reality there are a number of sub-steps or sub-allocations that occur. In addition there are a small number of budgeted General Expenses and Direct Charges that are allocated directly as a single step to affiliates.

2.3.3 Service Description Transparency

To enable evaluation of the cost incurrence test, the services provided to the regulated entity must be transparent, both from the recipient, and the provider perspective.

From a recipient perspective, each service must be described in a way that it reflects sub components and the activities involved so that the recipient can evaluate the extent to which the full service is needed.

From a provider perspective, the service must be described in such a way that it is recognizable by every employee delivering the service so that they can assess the relative effort expended and nature of the cost consumed by the service, which will ensure the service can be appropriately costed and will reflect what the provider delivers.

The services provided, and associated expenses (e.g., General Expenses and Direct Charges) and quantity and quality indicators, for any given year are described in detailed Service Schedules appended to the RCAM Confirmation Notice (Schedule 2 to the Agreement), to be signed by both the service provider and service recipient each year.

2.3.4 Demand Pull by Recipients

The RCAM will employ a “demand / pull” approach for allocating service costs. Specifically, the service recipient will pay for only those services required as if it was a stand-alone entity calling for services from an external “arms length” service provider. While both the service recipient and the provider may jointly define the exact nature of those services, ultimately, the recipient will be responsible to confirm the need for the service(s). Through the annual performance review process, the service recipient will confirm that the services being provided meet the service recipient’s requirements, and will ensure that changes are made to those services, if necessary.

2.4 Bases of Allocation

As a general principle, one is seeking to associate and attribute costs (direct and indirect costs) specifically with individual cost objects (in this case, departments, services or affiliates) on the basis of causality.

In reality however, there will be pools of indirect costs that cannot be associated specifically with each one of the cost objects in a group of cost objects. These pools of indirect costs are called "common" costs. In such cases, an allocator that most closely reflects causality must be used.

Allocator definitions for the allocators used in RCAM are included in Appendix A: RCAM Allocator Definitions.

In general, the allocators are selected to reflect:

- the nature of the specific department, service or expense being allocated; and
- the primary drivers of the associated costs.

Primary Cost Drivers

Effort:

Where costs (direct or indirect) have their causal root in effort and can be attributed specifically to each cost object (i.e. departments, service or affiliate) on the basis of time, this allocator (time) will be used, if available.

A quarterly, backward-looking, time study will be used to establish the relative effort expended by EI resources on services provided to EGD and all other affiliates, including EI departments. The time study process will be conducted in a manner consistent with what regulators in earlier regulatory decisions (e.g. Union Gas, TransCanada) have accepted regarding the use of time studies for establishing effort and allocating costs.

In general terms, the time study will be conducted at a detailed level and input sought from each EI staff member within the departments that deliver services to EGD.

For each participating EI department, time estimates are subjected to salary weightings to ensure that departmental costs are appropriately distributed to services and affiliates. Salary weightings are calculated both for the initial allocation to services, as well as for the secondary allocation to affiliates for each service.

The time study will provide an accounting of total time spent by departments on the delivery of services (100 % of staffs' time), as well the proportion of time spent by service on EGD and other affiliates, where identifiable (100% of each staff person's time on a service provided to affiliates). Estimates of the time spent by service will be captured in seven buckets;

- EGD specific;
- EI specific;
- Liquids Pipelines and Major Projects specific;
- Gas Pipelines and Other Distribution specific;
- Sponsored Investments specific;
- International specific; and
- Common time

Usage:

This allocator will be used where costs (direct and indirect) have their causal root in usage and can be attributed specifically to each cost object, on the basis of such usage. The most appropriate allocators include volume metrics such as system users, distance, trips, etc.

Primary Cost Drivers for Common Costs

Where, however, indirect costs cannot be specifically attributed to specific cost objects (which nevertheless provide benefit), the costs may be regarded as "common".

Complexity and Size:

Where these costs have their causal root in effort or usage (and neither specific time nor specific volume metrics can be associated and attributed), allocators will be sought that reflect

- relative complexity of the recipient to be used as a proxy for the likely effort (and hence time) required to service a cost object; or
- relative size of the recipient to be used as a proxy of the likely usage of service (or the likely complexity and hence effort) required to service a cost object.

When indirect costs cannot be attributed to specific cost objects on the basis of time or volume metrics, a relatively small group of allocators will be used. These include derivations of:

- Head Count
- Salaries
- Capital Employed

Relative Benefit:

Where drivers that clearly link to causality are not identifiable, the cost allocators used will be selected to reflect the relative benefit being received by the cost objects in question. The costs incurred were allocated to reflect the benefit experienced by a group of recipients relative to each other.

This is not in conflict with a "cost plus" basis of allocation versus a "market based pricing" mechanism because market based pricing is exactly that; a pricing mechanism, while cost plus is an "apportionment of cost" mechanism.

Stand Alone Principle:

In all cases there will be an underlying intention to allocate costs that are both needed by the recipient (incurrence test) and benefit the recipient (cost benefit test). The costs allocated for the benefit of the service will therefore be equal to or lower than the amount EGD would pay as a stand alone entity for a similar service from an external arms length provider.

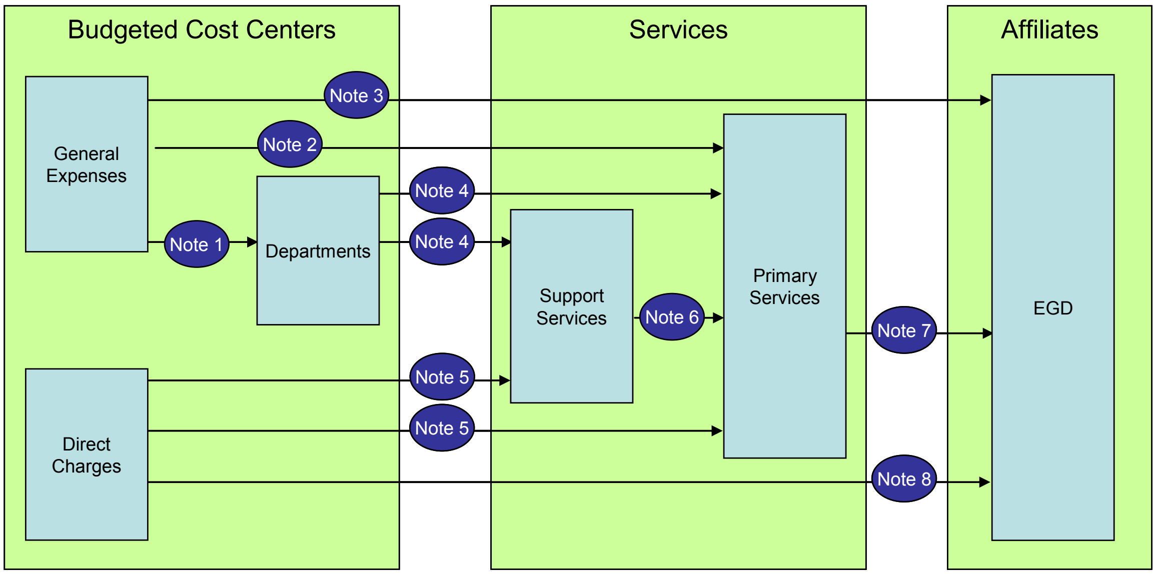
2.5 Currency Usage for Allocations and Direct Charges

Allocations and direct charges will be made in Canadian funds.

3 ALLOCATION

This section reviews the RCAM allocation model. It documents the mechanics and provides a brief rationale for each step.

RCAM Allocation Model



3.1 General Expenses-to-Departments Allocations

Note 1:

EI budgets contain a group of expenses labeled as "General Expenses". These expenses are separately budgeted for management purposes. Some of the General Expenses, however, are incurred for the benefit of Departments (EI only) and some for affiliates. In cases where the General Expenses represent costs incurred by individuals or groups of individuals, the allocation is made to departments in which the individuals reside.

General Expense[1]	Cost Driver	Allocator to Dept
Business Taxes	Usage of facility	Calgary Head Count
Rent & Leases	Usage of facility	Calgary Head Count
Employee Benefits	Usage	Salaries (segmented)
EI's Stock Options (SO), Phantom Stock Units (PSU) and Restricted Stock Units (RSU) Charges[2]	Usage	Head Count - specific
Other Employee Benefits	Usage	Salaries (segmented)
Corporate Law Legal Fees	Staff	Direct
Depreciation - Other Corporate	Direct & Usage	Direct (Plane & IT Projects) Calgary Head Count (other Depreciation)

[1] – General Expenses were not allocated to services provided by EPI and EGD as EI received "fully loaded" allocations from the originating entity.

[2] –

Stock Options (SO) Calc: The fair value of stock options is determined at the date of grant using the Black Scholes model. The number of the SOs vested each year is valued at the market price on the date of vesting, minus the grant price for those vested shares.

Phantom Stock Units (PSU) Calc: PSU holders receive notional units as if one unit was one common share. PSU holders receive cash awards following a three-year performance cycle. Awards are calculated for each outstanding unit at the end of the performance period using the EI weighted average share price and a performance multiplier. The performance multiplier is derived through a calculation of specified performance metrics in relation to a specified peer group of companies, relative to targets established at the time of the grant.

Restricted Stock Units (RSU) Calc: RSU holders receive cash per outstanding unit equal to EI's weighted average EI share price at the time of maturity, 35 months from the date of grant. The outstanding units accumulate notional dividends during their validity.

3.2 General Expenses-to-Primary Services Allocations

Note 2:

In cases where the General Expenses are not incurred based on individuals or groups of individuals and are not affiliate specific, the allocation will be made to the services they support.

General Expense	Cost Driver	Allocator to Service
Industry Associations	Usage	Direct
Corporate Secretarial Legal Fees	Usage	Direct

3.3 General Expenses-to-Affiliate Allocations

Note 3:

In cases where the General Expenses can be specifically identified with an affiliate, the costs will be directed to each affiliate respectively.

General Expense	Cost Driver	Allocator to Affiliate
Directors Fees & Expenses	Effort	Capital Employed
Depreciation - Risk Management System (50%)	Usage	System Usage

3.4 Department-to-Service Allocations

Note 4:

All department costs (loaded with applicable General Expenses) will be allocated to the respective services they provide.

In the majority of cases, staff costs represent a significant portion of the department costs and this clearly links effort to causality as the primary driver of the cost of delivering a service. The primary allocator of costs from Department-to-Services in this situation will be "salary-weighted time". (This will include those non-salary costs required to support the Department that are not material in their own right).

In cases where non-salary costs are significant, allocators other than salary-weighted time will be selected and depending on the nature of the costs are allocated (on the basis of causality), either:

- as a direct charge to the respective service; or
- on the basis of usage.

On this basis, all department costs will be allocated on time estimates to the respective services they provide with two exceptions – the Corporate Administration Department and Enterprise Financial System (EFS) Department, as explained below.

1) Due to the materiality of some of the non-salary related costs, the Corporate Administration Department will use:

   - direct allocation of material office administration costs to the Corporate Office Administration Service;
   - direct allocation of maintenance and licence fees related to the HRIS (PeopleSoft), to the Human Resource Information Systems (HRIS) Program Management and Development Service
   - direct allocation of maintenance and licence fees related to the Records Management System (Livelink) to the Records and Information Management Service;
   - direct allocation of maintenance and licence fees related to the Portal Suite of Applications (elink) to the Portal Suite Operations and Technical Support Service; and
   - the remaining costs are allocated based on time estimates to all services provided by the department. (i.e., Corporate Office Admin. Service, Expense System and Supply Chain Management).

2) The costs for supporting the Enterprise Financial Systems (EFS) will be incurred directly by multiple affiliates for the purpose of delivering enterprise financial services. For allocation purposes, the participating affiliates' original budget allocations are notionally aggregated and the charges are calculated based on affiliate user count. The difference between this affiliate calculation and the affiliate's original budget allocation (debit or credit) is allocated to the affiliate.

3.5 Direct Charges-to-Services Allocations

Note 5:
The "direct charges" will represent expenses incurred directly by EI which can be tracked on an affiliate specific basis. Direct charges of EI also include allocated costs from EGD and EPI for services provided by them to EI. These costs are added directly into the EI Services. These services will then be reallocated to the affiliates (including EGD and EPI). Where a portion of EGD costs allocated to EI would not be incurred for EGD on its own behalf they will not be re-allocated back to EGD.

3.6 Support Service-to-Primary Service Allocations

Note 6:
In establishing the RCAM, all services provided by EI will be identified, costed and made available to EGD for review. EGD will indicate which services are not directly required by them. Where these services are nevertheless regarded by EI as crucial to support the delivery of the services which EGD does need they are added in to those Primary Services that they support (See Appendix F: Support Service Loading for further service definitions). (The rationale underlying this support services loading is that it makes it comparable to an external service provider establishing a basic infrastructure and operational support to conduct a service delivery business. The costs of such support services will be included in the pricing of primary services to the customers of the external service provider). The distinction between "primary" services and "support" services and the approach to classification is set out below:

Classifying Services as Support vs. Primary:

The following decision chart is used to classify services as either a Primary or Support Service:

Question 1:

Does the affiliate agree that the service is needed directly by them?

- If the answer is "yes" the service is likely to pass the incurrence test as a valid primary service.
- If the answer is "no" a 2nd question will be asked, namely;

Question 2:

Does the affiliate agree that the service is necessary to support the services that are needed directly by them?

- If the answer is "yes" the services is likely to pass the incurrence test to the extent that the service it supports passes the cost incurrence test and is therefore a valid support service.
- If the answer to question 2 "no", then no part of the "support'' service cost will be allocated to the affiliate.

Based on the decision chart established above, the services will be divided into "support" and "primary" services. The nature of each support service will help to determine which primary services receive the costs from each respective support service (i.e., which primary services benefit from the support service). Therefore, the nature of each "support" service is examined and segmented into three groups, namely those that provide "content" based support, those that provide "infrastructural" based support, and those that provide "resource" based support to the primary services.

Loading of Support to Primary Service

Although time estimates were also obtained for determining the extent to which each of the support services were considered to be directly supporting the affiliates, no part of the support service is allocated directly to any affiliate. The full cost of each support service is loaded into the primary services they support. The fully loaded cost of the primary service is then allocated to the affiliate based on the time estimates provided for the respective primary service. Similarly, the common portion would be allocated as determined for the residual of the primary service.

Infrastructural Support Services are considered to be needed by all EI Departments in Calgary providing Primary Services and are therefore allocated across all these Primary Services, based on a Derived Head Count (DHC) of the Primary Service. (Appendix A: RCAM Allocator Definitions)

Content Support Services are allocated to the specific primary services they support based on the relationship of the respective primary service costs. (The DHC of each department is not a reasonable base for allocation for content support services as the volume of people is not the driver of the need for these support services.)

The Resource Support Service is allocated to the services provided by the departments they directly supported as per the time estimation study results.

The summary of support service allocations to Primary Services are listed below:

Support Service	Driver	Allocator
Content Support Services		
Financial Reporting	Complexity & or Usage	Service cost
Certification of Financial Reporting & Internal Controls	Complexity & or Usage	Service cost
Consolidation Accounting	Complexity & or Usage	Service cost
Budgeting & Forecasting	Complexity & or Usage	Service cost
Infrastructure Support Services		
Air Travel for Company Personnel	Usage	Trips[1]
Corporate General Accounting	Usage	Transactions
Corporate Office Administration	Usage	DHC
Environment, Health & Safety	Usage	DHC
Helpdesk, Network, Infrastructure & Hardware Support	Usage	DHC
Information System Support Applications	Usage	DHC
Invoice Processing and Payment	Usage	DHC
IT Project Management & Support	Usage	DHC
IT Software Support & Maintenance	Usage	DHC
Payroll & Benefits Processing	Usage	DHC
Resource Support Service		
Financial Projects	Usage	Direct

[1] Trips – In determining the allocation of the aviation service for transporting company personnel to primary services, the number of flights and the individuals traveling per flight were extracted from the flight logs. With this information and an estimated cost per flight (based on an average cost per km to operate the aircraft and the estimated km traveled per flight) a cost equally shared per individual per flight could be derived. The cost would then track with the individual to their respective affiliate or department and be allocated to the services they support based on the results of the time estimation study. Costs derived in the same manner for each non-Enbridge employee on every flight were treated as a residual corporate cost.

3.7 Service-to-Affiliate Allocations

Note 7:

The link between the basis of allocation and causality is regarded as crucial to the service being able to pass the cost incurrence test. Time is regarded as one of the most supportable causal factors. The methodology therefore seeks to allocate as much of the service cost as possible on the basis of time actually spent delivering the service to affiliates.

Therefore, three broad parameters are considered in the allocation of the cost of the service;

1) How much of the effort spent on delivering the service can be identified and attributable directly to EGD?

2) How much of the effort spent on delivering the service can be identified and attributable directly to other affiliates?
3) How much of the effort spent on delivering the service cannot be identified directly attributable to any affiliate (common cost)?

These proportions have been established by the Time Study.

The effort spent on delivering the Primary Service to EGD versus other affiliates has been identified and used to attribute the portion of the cost of the Primary Service to EGD and other affiliates on the basis of salary-weighted time estimates.

The residual pool of common time is then allocated on a different allocator selected to align as closely as possible to causality.

Not all "common costs" benefit every one of the affiliates. This has specific relevance to the Minority Investments (MIs) which. are sometimes merely financial assets of EI and sometimes fully owned and operated under contracts, etc. The benefiting affiliates will be identified before selecting the allocator which will reflect the most appropriate proxy for causality. See Appendix A for the definition of all acronyms used below.

Service	External Driver	Effort Required by EI to support the acquisition and holding of Financing Minority Interests (FMIs)	Allocator
EGD Required Primary Services Provided Solely by EI (i.e. EGD has no capability to self-serve)			
Board of Directors Support	Company complexity & number of meetings	Yes	FCER
Business Development[1]	Mergers & Acquisitions (M&A) activity	No	ACER
Capital Market Financing & Access	Financing activity	Yes	FCER
Cash Management & Banking	Cash volume	No	EGD % of Direct Time[3]
Enterprise IT Program Management	IT programs	No	ACER
Enterprise IT Strategy Planning & Management	IT assets	No	ACER
External Audit Coordination	Audit size (hence company complexity)	Yes	Same as Audit Fees
Government Relations	Regulations	No	ACER
Human Resource Information Systems (HRIS) Program Management and Development	HRIS IT asset usage	No	AHC
Investor Services	M&A and financing activity	Yes	FCER
Rate Regulated Entity Support	Regulation and company complexity	No	N/A
Records and Information Management	Transactions, contracts, documents	No	System Users
Risk Assessment and Management	Entity risk	Yes	FCER

Service	External Driver	Effort Required by EI to support the acquisition and holding of Financing Minority Interests (FMIs)	Allocator
Supply Chain Management	Raw material volumes	No	ACER
EGD Required Primary Services Provided as a Supplement to EGD's Own Capabilities			
Audit & Accounting Advice	Company complexity	Yes	FCER
Business & Economic Financial Analysis	M&A activity	No	EGD % of Direct Time[3]
Consolidation and Planning System Technical Support (Khalix)	IT asset usage	No	System Users
Corporate Compliance	Company complexity	No	ACER
Emerging Energy Technology Research	New technologies	No	ACER
Employee and Labour Relations	Employees, Unionized employees	No	AHC
Employee Development	Employees	No	Non Union EFTE
Expense System Management & Technical Support (Oracle iExpense)	IT asset usage	No	System Users
Financial and Project Accounting System Technical Support (Oracle)	IT asset usage	No	System Users
Gas Supply, Storage, and Transportation Strategy	Raw material volumes	No	EGD % of Direct Time[3]
Government Relations	Regulations	No	ACER
Human Resource Advice	Employees	No	AHC
Industry Relations and Corporate Social Responsibility (CSR)	Customer base and public Interest	No	ACER
Insurance Claims Support, Strategy and Management	Entity risk	Yes	Same as Insurance Premiums
Legal Advice	Regulation, Contracts, M&A	No	ACER
Planning, Management & Execution of Internal Audits	Company complexity	Yes	Same as Audit Fees
Portal Suite Operations and Technical Support	Portal IT asset usage	No	System Users
Strategic Planning[2]	Complexity (company & markets)	Yes	FCER
Tax Reporting & Planning	Legal Entities, M&A, financing	No	EGD % of Direct Time[3]
Total Compensation and Benefits	Employees	No	AHC
Primary Services Not Required by EGD			
Aerial Pipeline Surveillance	Not Required by EGD	N/A	N/A

Service	External Driver	Effort Required by EI to support the acquisition and holding of Financing Minority Interests (FMIs)	Allocator
External Communications	Customer base and public interest	No	ACER
Gas Accounting	Not Required by EGD	N/A	N/A
Gas Contract Accounting	Not Required by EGD	N/A	N/A
Internal Employee Communications	Employees	No	AHC
Pension Plan Asset Management and Administration	Already charged separately to EGD	N/A	N/A
Reservoir Engineering	Not Required by EGD	N/A	N/A
Tax Advice	Legal Entities, M&A, financing	No	EGD % of Direct Time[3]

[1] Common Business Development Costs accepted by EGD include only the proportion related to costs incurred by the Ontario Business Development department

[2] Common Strategic Planning costs are not accepted by EGD and are regarded as an EI cost

[3] Where time estimates allocated over 80% of the primary service costs specifically to affiliates, it is deemed reasonable to assume the proportion of effort between EGD specific and "Other" specific affiliates was a fair representation for the allocation of the common (to the benefit of all affiliates) effort.

3.8 Direct Charges-to-Affiliate Allocations

Note 8:

EI budgets contain a group of expenses labeled as "Direct Charges". These charges are separately budgeted for management purposes. They, however, are incurred specifically for affiliates and the details may be tracked directly for the benefit of a particular affiliate.

Direct Charges	Driver	Allocator to Affiliate
Depreciation – Risk Management System	Usage/ Transactions	Direct
Direct EFS Charge (Credit)	Usage	Direct
Directors Fees and Expenses	Company complexity & number of meetings	FCER
EGD Stock Based Compensation[1]	Usage	AHC – specific
Insurance Premiums	Risk	Direct

[1] Refer to footnote in Note 1

4 RETURN ON INVESTED CAPITAL

ARC allows for a return on "invested capital" as indicated below.

> *2.3.10 Where it can be established that a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility acquires from an affiliate, the utility shall pay no more than the affiliate's fully-allocated cost to provide that service,*

> *product, resource or use of asset. The fully-allocated cost may include a return on the affiliate's invested capital. The return on invested capital shall be no higher than the utility's approved weighted average cost of capital.*

A return on invested capital has not been incorporated as a part of each Primary Services' fully allocated cost, but is included as a separate charge in RCAM.

The "invested capital" has been defined as the NBV (net book value) of PPE (property, plant and equipment) assets of EI required to provide the services.

5 UPDATE AND REVIEW PROCESS

The RCAM is a dynamic document which must be reviewed and updated periodically to ensure its relevance to both EI and EGD to reflect organizational changes of the business and any changes to the regulatory environment. There are five key areas that need to be addressed.

5.1 Service Schedule Detail Reviews

The performance review & evaluation and dispute resolution clauses from the Service Agreement (SA) may highlight changes that need to be reflected in the Service Schedules. While performance feedback may occur throughout the life of the SA, a formal discussion shall take place periodically, at least annually, to ensure changes are documented and incorporated into the next SA and rate case filing. Changes may occur in the service definitions, service offerings by department, expected service deliverables and quality & quantity descriptors.

5.2 Service Review for Relevancy to EGD

The second step in the review process is a review for service relevancy to EGD. Reflecting on the performance feedback process and service schedule reviews, services allocated to EGD shall be reviewed, as part of the performance review process, to ensure that they still meet the cost incurrence test. In addition, services that are currently deemed support services or have not in the past been allocated to EGD shall be reviewed to ensure proper treatment. Changes made to the Service Schedules shall be captured within a revised version of the RCAM, updated annually.

5.3 Time Estimation Study

Once the Service Schedules have been updated with changes highlighted from 5.1 and 5.2, the detailed time estimation study will be conducted, if necessary, to estimate the future time that the EI corporate office will provide to the respective services. The results of the time estimation study are used as an input into the allocation model calculation. The time estimation study will be conducted at the end of each quarter.

5.4 Allocator Review

Concurrently with the time estimation study, a review of the cost allocators will be conducted. This review shall include a determination of whether or not the allocator is still appropriate for use with the service or expense in question, an evaluation of whether the information required for its calculation is available and whether or not the calculation definition needs to be revised based on an organizational change within Enbridge. Changes shall be documented, including the rationale for the change, in a revised version of the RCAM.

5.5 Cost Calculation

Once all Service Schedules are updated, the time estimation study complete and a review of the allocators complete, the cost allocation model shall be revised and run to determine the specific cost allocations from EI to EGD.

Appendix A: RCAM Allocator Definitions

The following table provides the definition of each allocator used in the Regulatory Cost Allocation Methodology (“RCAM”) to determine the service charges from Enbridge Inc. (“EI”) to Enbridge Gas Distribution Inc. (“EGD”). The allocators are separated into two categories:

1. Allocations to Service: represent allocators used to determine the cost of services.
2. Allocations to Affiliates: represent allocators used to determine service charges attributable to EGD.

Allocator	Definition	
Allocation to Service		
Time (before salary weighting)	Numerator	Sum of all employee time estimates (% of time) from a specific department to a specific service.
	Denominator	Number of employees in the department which provided time estimates.
General Salary Weighting	Salary grade mid-point for individual time study participant from a specific department.	
Salary Weighted Time	General salary weighting for a specific individual multiplied by the individual's time estimate to each service.	
Enbridge Inc. Headcount (EIHC)	Numerator	Number of EI staff of receiving department (including planned full-time and part-time positions for the respective budget year).
	Denominator	All EI staff (including planned full-time and part-time positions for the respective budget year).
Calgary Headcount (CHC)	Numerator	Number of EI staff of receiving department located in Calgary (including planned full-time and part-time positions for the respective budget year).
	Denominator	All staff located in the Calgary office including both EI as well as other affiliate staff (including planned full-time and part-time positions for the respective budget year).
Derived Primary Service Headcount (DHC)	Numerator	Derived HC by Primary Service (By each primary service, sum of head count in each department multiplied by the allocators to service).
	Denominator	All EI staff (including planned full-time and part-time positions for the respective budget year).
		The calculation of DHC does not include any primary service components provided by EGD (e.g. Reservoir Engineering) or EPI as they are deemed already "fully" loaded (e.g. depreciation and 54% burden costs).
Salaries	Numerator	Sum of (Employees in salary range x range mid-point salary) for each salary range in Enbridge Inc. department.
	Denominator	Sum of (Employees in salary range x range mid-point salary) for each salary range in all relevant Enbridge Inc. departments.
Direct		The department cost element, general expense or direct charge is directly loaded into the service which it supports.
Value of Trips	Numerator	Value of corporate jet allocation to a specific Primary Service (derived from time estimation study)
	Denominator	Sum value of all corporate jet allocations to Primary Services.
Financial Project Resource Usage	Allocated equally across the number of Primary Services supported by the Financial Project Support Service.	
Primary Service Cost	Numerator	Specific Primary Service cost prior to support cost loading
	Denominator	Sum of the charges (prior to Support Service cost loading) related to Primary Services which require support services

Allocator	Definition	
Allocation to Affiliate		
Time (before salary weighting)	Numerator A	Sum of all employee time estimates from a specific department for a specific Primary Service allocation to EGD.
	Numerator B	Sum of all employee time estimates from a specific department for a specific Primary Service allocation to Other Affiliates.
	Numerator C	Sum of all employee time estimates from a specific department for a specific Primary Service allocation to All Affiliates.
	Denominator	Number of employees in the department which provided time estimates.
Service Specific Salary Weighting	Numerator	Salary grade mid-point for individual time study participant from a specific department.
	Denominator	Sum of all employee salary grade mid-points, which allocate to a specific service, for a specific department.
Service Specific Salary Weighted Time	Service specific salary weighting for a specific individual multiplied by the individual's time estimate to each affiliate for a specific service.	
EGD % of Salary-Weighted Direct Time	Numerator	Value of direct salary-weighted time-based allocation to EGD.
	Denominator	Value of direct salary-weighted time-based allocation to EGD + Value of direct salary-weighted time-based allocation to Other Affiliates.
Financing Capital Employed Ratio (FCER)	Numerator	EGD's Capital Employed without the Purchase Premium.
	Denominator	Enbridge's Consolidated Capital Employed (including all purchase premiums) plus a gross-up, to reflect full ownership, of EEP, the Saskatchewan Pipeline portion of the Enbridge Income Fund, plus all other Minority Equity Investments.
Adjusted Capital Employed Ratio (ACER)	Numerator	EGD's Capital Employed without the Purchase Premium.
	Denominator	EI's capital employed, without the Purchase Premium, without equity investments but increased to reflect what it would be if EEP and the Saskatchewan Pipeline portion of the Enbridge Income Fund were wholly owned.
Enterprise Full time equivalents (EFTE) or Affiliate Headcount (AHC)	Numerator	Staff of receiving Affiliate (including planned full-time and part-time positions for the respective budget year).
	Denominator	Total staff of all Enbridge Affiliates (including planned full-time and part-time positions for the respective budget year).
Non-Union Enterprise Full time equivalents (Non-Union EFTE)	Numerator	Staff of receiving Affiliate (including planned full-time and part-time positions for the respective budget year) that do not belong to a unionized body.
	Denominator	Total staff of all Enbridge Affiliates (including planned full-time and part-time positions for the respective budget year) that do not belong to a unionized body.
Direct	The general expense or direct charge is directly allocated to the affiliate which causes the expense or charge.	
Audit Fees	Numerator	Value of EGD Audit Fee allocation.
	Denominator	Total Audit Fee budget for Enbridge Inc.
Insurance Premiums	Numerator	Value of EGD Insurance Premium allocation.
	Denominator	Total Insurance premium budget for Enbridge Inc.
System Users	Numerator	Number of EGD system users.
	Denominator	Total system users across all affiliates.
System Usage	Numerator	EGD Transaction volumes + EGD Earnings at Risk.
	Denominator	All Affiliate transaction volumes + All Affiliate Earnings at Risk.

Allocator	Definition
Allocation to Affiliate	
Return on Invested Capital	The “invested capital” has been defined as the NBV (net book value) of PPE (property, plant and equipment) of EI required to provide the services. Calculation: Invested Assets (PPE) for EI x FCER x WACC (EGD’s weighted average cost of capital as approved by the Ontario Energy Board from time-to-time).

REGULATORY COST ALLOCATION METHODOLOGY CONFIRMATION NOTICE

SERVICES TO BE PROVIDED DURING THE YEAR XXXX AND ASSOCIATED COSTS

We have discussed the nature and level of the services to be provided by Enbridge Inc. to Enbridge Gas Distribution Inc. (including Tecumseh Gas Storage) during the year XXXX pursuant to the Agreement, and agree that the services provided, as described in Appendix B hereto, and the costs to be charged as detailed in Appendix A hereto, are acceptable.

TOTAL COST $XXXXXXXX

ENBRIDGE INC.

______________________________	______________________________
J.R. Bird, Executive VP, CFO & Corporate Development	Date
______________________________	______________________________
J. K. Whelen, Senior VP & Controller	Date

ENBRIDGE GAS DISTRIBUTION INC.

______________________________	______________________________
G. Jarvis, President	Date
______________________________	______________________________
M. Boyce, VP Law & Information Technology	Date

Schedule 2(a) to the Intercorporate Services Agreement between Enbridge Inc. and Enbridge Gas Distribution Inc., dated January 1, 2011 (the "Agreement")

REGULATORY COST ALLOCATION METHODOLOGY CONFIRMATION NOTICE

SERVICES TO BE PROVIDED DURING 2011 YEAR AND ASSOCIATED COSTS

We have discussed the nature and level of the services to be provided by Enbridge Inc. to Enbridge Gas Distribution Inc. (including Tecumseh Gas Storage) during the year 2011 pursuant to the Agreement, and agree that the services provided, as described in Appendix B hereto, and the costs to be charged as detailed in Appendix A hereto, are acceptable.

TOTAL COST $26,667,504

ENBRIDGE INC.

J.R. Bird, Executive VP, CFO & Corporate Development — Date: February 16, 2012

J. K. Whelen, Senior VP & Controller — Date: February 16, 2012

APPROVED AS TO FORM
ENBRIDGE LAW TP

ENBRIDGE GAS DISTRIBUTION INC.

G. Jarvis, President — Date: March 5, 2012

M. Boyce, VP Law & Information Technology — Date: March 5, 2012

ENB LL 24466969

Schedule 2(b) to the Intercorporate Services Agreement between Enbridge Inc. and Enbridge Gas Distribution Inc., dated January 1, 2012 (the "Agreement")

REGULATORY COST ALLOCATION METHODOLOGY CONFIRMATION NOTICE

SERVICES TO BE PROVIDED DURING 2012 YEAR AND ASSOCIATED COSTS

We have discussed the nature and level of the services to be provided by Enbridge Inc. to Enbridge Gas Distribution Inc. (includin g Tecumseh Gas Storage) during the year 2012 pursuant to the Agreement, and agree that the services provided, as described in Appendix B hereto, and the costs to be charged as detailed in Appendix A hereto, are acceptable.

TOTAL COST $31,765,147

ENBRIDGE INC.

J.R. Bird, Executive VP, CFO & Corporate Development — Date: May 15, 2012

J. K. Whelen, Senior VP & Controller — Date: May 15, 2012

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM
ENBRIDGE LAW TP

D. G. Jarvis, President — Date: MAY 3, 2012

N. K. Kishinchandani, Vice President, Finance — Date: May 3, 2012

Appendix "A" to the Regulatory Cost allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

2012 RCAM Allocations to EGD and Other Affiliates

	Services / Direct Charges	EGD Allocation: EGD Direct Allocation	EGD Allocation: EGD Common Allocation	EGD Allocation: Direct Charge & General Expense Allocation	EGD Allocation: EGD Return on Invested Capital	EGD Allocation: Total Allocation To EGD	Other Allocation: Direct Allocation	Other Allocation: Common Allocation	Other Allocation: Direct Charges	Other Allocation: Total Allocation to Other	Total Allocations
Primary Services	2. Audit & Accounting Advice	$ 45,122	$ 46,147			$ 91,270	$ 826,218	$ 286,566		$ 1,112,784	$ 1,204,054
	3. Board of Directors Support	$ 541,575	$ 227,793			$ 769,368	$ 4,605,108	$ 1,414,549		$ 6,019,657	$ 6,789,025
	4. Business & Economic Financial Analysis	$ -	$ -			$ -	$ 5,634,169	$ -		$ 5,634,169	$ 5,634,169
	5. Business Development	$ 736,918	$ -			$ 736,918	$ 20,023,366	$ -		$ 20,023,366	$ 20,760,284
	6. Capital Market Financing & Access	$ 668,572	$ 351,602			$ 1,020,173	$ 5,445,415	$ 2,183,378		$ 7,628,793	$ 8,648,966
	7. Cash Management & Banking	$ 293,455	$ 187,619			$ 481,073	$ 1,944,137	$ 1,242,973		$ 3,187,109	$ 3,668,182
	8. Consolidation and Planning System Technical Support (Khalix)	$ 5,160	$ 239,929			$ 245,089	$ 72,239	$ 472,831		$ 545,071	$ 790,160
	9. Corporate Compliance	$ 94,191	$ 103,011			$ 197,202	$ 439,213	$ 551,026		$ 990,239	$ 1,187,441
	10.Industry Relations & Corporate Social Responsibility (CSR)	$ 180,972	$ 203,394			$ 384,365	$ 5,670,597	$ 1,087,994		$ 6,758,591	$ 7,142,956
	11. Emerging Energy Technology Research	$ -	$ -			$ -	$ 5,125,015	$ -		$ 5,125,015	$ 5,125,015
	12. Employee Development	$ 763,883	$ 496,685			$ 1,260,568	$ 2,374,424	$ 1,581,569		$ 3,955,993	$ 5,216,561
	13. Enterprise IT Program Management	$ -	$ 868,494			$ 868,494	$ -	$ 4,645,752		$ 4,645,752	$ 5,514,246
	14. Enterprise IT Strategy Planning & Management	$ 149,655	$ 474,460			$ 624,115	$ 2,293,244	$ 2,537,987		$ 4,831,231	$ 5,455,347
	15. Expense System Management & Technical Support (Oracle	$ 736	$ 94,754			$ 95,490	$ 82,287	$ 308,731		$ 391,017	$ 486,508
	16. External Audit Coordination	$ 84,158	$ 19,241			$ 103,399	$ 532,819	$ 55,656		$ 588,475	$ 691,874
	17. External Communications	$ -	$ -			$ -	$ 5,423,997	$ -		$ 5,423,997	$ 5,423,997
	18. Financial and Project Accounting System Technical Support	$ 25,397	$ 326,764			$ 352,161	$ 209,526	$ 1,064,673		$ 1,274,199	$ 1,626,360
	20. Gas Contract Administration	$ -	$ -			$ -	$ 1,075,049	$ -		$ 1,075,049	$ 1,075,049
	21. Gas Supply, Storage, and Transportation Strategy	$ -	$ -			$ -	$ -	$ 511,868		$ 511,868	$ 511,868
	22. Government Relations	$ 44,917	$ -			$ 44,917	$ 2,015,142	$ -		$ 2,015,142	$ 2,060,059
	23. HRIS Management and Technical Support	$ -	$ 3,009,273			$ 3,009,273	$ -	$ 6,670,575		$ 6,670,575	$ 9,679,848
	24. Human Resource Advice	$ 60,686	$ 141,094			$ 201,779	$ 2,325,123	$ 312,759		$ 2,637,882	$ 2,839,661
	26. Insurance Claims Support, Strategy and Management **(Combined)**	$ 77,773	$ 30,467			$ 108,240	$ 1,846,781	$ 184,084		$ 2,030,864	$ 2,139,104
	27. Internal Employee Communications	$ -	$ -			$ -	$ 4,590,078	$ -		$ 4,590,078	$ 4,590,078
	28. Investor Services	$ 745,415	$ 138,422			$ 883,837	$ 10,614,658	$ 859,575		$ 11,474,233	$ 12,358,070
	30. Legal Advice	$ 448,128	$ 66,268			$ 514,396	$ 7,561,139	$ 354,481		$ 7,915,621	$ 8,430,016
	31. Pension Plan Asset Management and Administration	$ -	$ -			$ -	$ 859,939	$ -		$ 859,939	$ 859,939
	32. Planning, Management & Execution of Internal Audits	$ 132,879	$ 58,648			$ 191,528	$ 2,129,595	$ 169,648		$ 2,299,243	$ 2,490,771
	33. Rate Regulated Entity Support	$ 253,904	$ -			$ 253,904	$ 242,871	$ 19,964		$ 262,835	$ 516,739
	34. Records and Information Management	$ -	$ 538,352			$ 538,352	$ -	$ 9,761,718		$ 9,761,718	$ 10,300,070
	36. Risk Assessment and Management	$ 685,727	$ 192,734			$ 878,461	$ 10,977,524	$ 1,196,843		$ 12,174,367	$ 13,052,828
	37. Strategic Planning	$ 327,890	$ -			$ 327,890	$ 6,625,362	$ -		$ 6,625,362	$ 6,953,252
	38. Supply Chain Management	$ -	$ 39,706			$ 39,706	$ 37,794	$ 212,398		$ 250,192	$ 289,899
	39. Tax Advice	$ -	$ -			$ -	$ 903,288	$ -		$ 903,288	$ 903,288
	40. Tax Reporting & Planning	$ 54,275	$ 1,033			$ 55,308	$ 3,019,781	$ 57,485		$ 3,077,265	$ 3,132,573
	41. Total Compensation and Benefits	$ 498,199	$ 1,283,611			$ 1,781,809	$ 1,883,697	$ 2,845,346		$ 4,729,043	$ 6,510,852
	42. Employee and Labour Relations (Combined)	$ 353,457	$ 124,744			$ 478,201	$ 302,698	$ 276,517		$ 579,215	$ 1,057,416
	43. Portal Suite Operations & Technical Support	$ -	$ 330,881			$ 330,881	$ -	$ 733,455		$ 733,455	$ 1,064,336
	Total Service Charges	**$ 7,273,043**	**$ 9,595,124**	**$ -**	**$ -**	**$ 16,868,167**	**$ 117,712,291**	**$ 41,600,401**	**$ -**	**$ 159,312,693**	**$ 176,180,860**
General Expenses & Direct Charges	Direct EFS Charge **(Credit)**			$ (2,314,784)		$ (2,314,784)				$ -	$ (2,314,784)
	Directors Fees & Expenses			$ 744,819		$ 744,819			$ 4,625,181	$ 4,625,181	$ 5,370,000
	Depreciation - Risk Management System			$ 64,951		$ 64,951			$ 1,213,619	$ 1,213,619	$ 1,278,570
	Insurance Premiums			$ 8,483,868		$ 8,483,868			$ 51,260,660	$ 51,260,660	$ 59,744,528
	EGD Stock Based Compensation Charge			$ 7,549,229		$ 7,549,229			$ -	$ -	$ 7,549,229
	Total Direct Charges	**$ -**	**$ -**	**$ 14,528,083**	**$ -**	**$ 14,528,083**	**$ -**	**$ -**	**$ 57,099,460**	**$ 57,099,460**	**$ 71,627,543**
Not Allocated To EGD	Non-EGD Related Charges Not Allocated to Services									$ 22,096,427	$ 22,096,427
	Support Services Loaded to **Non-EG**D Related Co's									$ 3,212,738	$ 3,212,738
	Adjustment to EI Corp. Gen. Acct.									$ 778,099	$ 778,099
	EFS True Up									$ 2,314,784	$ 2,314,784
	Directors Fee Credit to EGD (Allocated to Other)									$ -	$ -
	Return on Invested Capital				$ 368,896	$ 368,896					$ 368,896
	Total RCAM Allocations to EGD and Other Affiliates	**$ 7,273,043**	**$ 9,595,124**	**$ 14,528,083**	**$ 368,896**	**$ 31,765,147**	**$ 117,712,291**	**$ 41,600,401**	**$ 57,099,460**	**$ 244,814,200**	**$ 276,579,347**

Service charge breakdowns are provided in the accompanying schedules
Effective 2012, please note the following:
1. Two primary services have been combined, Insurance Claims Support and Insurance Strategy and Management.
2. Audit Fees **(Direct Charge) have** been removed, as **they are** no longer accounted for under **the** RCAM.

Accompanying Schedule to Appendix "A" to the Regulatory Cost allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Primary Services Cost Breakdown

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	**Department**	A	B	C = A x B	D	E = C x D	F	G = F x C	FCER	H = G x FCER	I = E + H
2. Audit & Accounting Advice	Corporate Controller (10047)	$ 15,939,163	5.27%	$ 839,455	3.00%	$ 25,184	30.00%	$ 251,836	13.87%	$ 34,930	$ 60,113
	Audit Services (Calgary) (10050)	$ 2,598,546	4.60%	$ 119,473	9.00%	$ 10,753	11.00%	$ 13,142	13.87%	$ 1,823	$ 12,575
	Support Services	$ 43,594,682	0.56%	$ 245,126	3.75%	$ 9,186	27.63%	$ 67,735	13.87%	$ 9,395	$ 18,581
	TOTAL	**$ 62,132,391**		**$ 1,204,054**		**$ 45,122**		**$ 332,714**		**$ 46,147**	**$ 91,270**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	**Department**	A	B	C = A x B	D	E = C x D	F	G = F x C	FCER	H = G x FCER	I = E + H
3. Board of Directors Support	CEO (10000)	$ 12,954,780	11.11%	$ 1,439,420	19.00%	$ 273,490	0.00%	$ -	13.87%	$ -	$ 273,490
	CFO (10045)	$ 3,719,515	4.02%	$ 149,528	14.00%	$ 20,934	0.00%	$ -	13.87%	$ -	$ 20,934
	Corporate Secretarial (10070)	$ 4,423,865	50.56%	$ 2,236,785	2.00%	$ 44,736	6.00%	$ 134,207	13.87%	$ 18,615	$ 63,350
	Total Compensation (10091)	$ 3,829,233	7.22%	$ 276,336	0.00%	$ -	100.00%	$ 276,336	13.87%	$ 38,328	$ 38,328
	Executive VP Corporate Law (10078)	$ 3,765,602	10.00%	$ 376,560	0.00%	$ -	0.00%	$ -	13.87%	$ -	$ -
	Corporate HR (10092)	$ 3,946,946	2.08%	$ 82,228	0.00%	$ -	100.00%	$ 82,228	13.87%	$ 11,405	$ 11,405
	People and Partners (10094)	$ 3,898,081	33.33%	$ 1,299,360	10.00%	$ 129,936	70.00%	$ 909,552	13.87%	$ 126,155	$ 256,091
	HR Enterprise Business Solutions (10089)	$ 2,001,904	1.01%	$ 20,221	0.00%	$ -	100.00%	$ 20,221	13.87%	$ 2,805	$ 2,805
	Support Services	$ 43,594,682	2.08%	$ 908,585	7.98%	$ 72,480	24.19%	$ 219,797	13.87%	$ 30,486	$ 102,966
	TOTAL	**$ 82,134,609**		**$ 6,789,025**		**$ 541,575**		**$ 1,642,342**		**$ 227,793**	**$ 769,368**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	**Department**	A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
5. Business Development	CEO (10000)	$ 12,954,780	11.11%	$ 1,439,420	15.00%	$ 215,913	0.00%	$ -	15.75%	$ -	$ 215,913
	CFO (10045)	$ 3,719,515	8.04%	$ 299,057	5.00%	$ 14,953	0.00%	$ -	15.75%	$ -	$ 14,953
	Corporate Controller (10047)	$ 15,939,163	2.11%	$ 335,782	10.00%	$ 33,578	0.00%	$ -	15.75%	$ -	$ 33,578
	Tax Services (Calgary) (10049)	$ 3,162,738	12.54%	$ 396,765	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Insurance Risk (10051)	$ 1,108,561	0.00%	$ -	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Public and Government Affairs (10072)	$ 16,935,260	7.69%	$ 1,302,712	5.02%	$ 65,428	0.00%	$ -	15.75%	$ -	$ 65,428
	Corporate Law (10077)	$ 5,979,072	14.94%	$ 893,425	5.00%	$ 44,671	0.00%	$ -	15.75%	$ -	$ 44,671
	Pension & Benefits (10096)	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Corporate HR (10092)	$ 3,946,946	4.17%	$ 164,456	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Labour Relations (10093)	$ 1,014,064	15.79%	$ 160,115	20.00%	$ 32,023	0.00%	$ -	15.75%	$ -	$ 32,023
	Alternative and Emerging Technology (10106)	$ 5,332,830	17.17%	$ 915,738	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Corporate Development and Planning (10107)	$ 9,949,334	44.94%	$ 4,471,611	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Investment Review (10109)	$ 2,423,985	27.13%	$ 657,621	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Executive VP Corporate Law (10078)	$ 3,765,602	10.00%	$ 376,560	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	HR Enterprise Business Solutions (10089)	$ 2,001,904	2.02%	$ 40,443	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Support Services	$ 43,594,682	21.21%	$ 9,247,041	3.55%	$ 328,238	0.00%	$ -	15.75%	$ -	$ 328,238
	EGD Charge	$ 1,716,941	3.47%	$ 59,537	3.55%	$ 2,113	0.00%	$ -	15.75%	$ -	$ 2,113
	TOTAL	**$ 133,545,379**		**$ 20,760,284**		**$ 736,918**		**$ -**		**$ -**	**$ 736,918**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	**Department**	A	B	C = A x B	D	E = C x D	F	G = F x C	FCER	H = G x FCER	I = E + H
6. Capital Market Financing & Access	CEO (10000)	$ 12,954,780	2.22%	$ 287,884	20.00%	$ 57,577	0.00%	$ -	13.87%	$ -	$ 57,577
	Investor Relations (10043)	$ 2,423,890	10.99%	$ 266,362	5.00%	$ 13,318	19.00%	$ 50,609	13.87%	$ 7,019	$ 20,337
	Treasury (10044)	$ 7,222,792	39.56%	$ 2,857,368	6.00%	$ 171,442	43.00%	$ 1,228,668	13.87%	$ 170,416	$ 341,858
	CFO (10045)	$ 3,719,515	18.34%	$ 682,223	15.00%	$ 102,333	0.00%	$ -	13.87%	$ -	$ 102,333
	Corporate Secretarial (10070)	$ 4,423,865	13.48%	$ 596,476	3.00%	$ 17,894	16.00%	$ 95,436	13.87%	$ 13,237	$ 31,131
	Support Services	$ 43,594,682	9.08%	$ 3,958,653	7.73%	$ 306,007	29.31%	$ 1,160,267	13.87%	$ 160,929	$ 466,936
	TOTAL	**$ 74,339,523**		**$ 8,648,966**		**$ 668,572**		**$ 2,534,980**		**$ 351,602**	**$ 1,020,173**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	**Department**	A	B	C = A x B	D	E = C x D	F	G = F x C	Time	H = G x Time	I = E + H
7. Cash Management & Banking	Treasury (10044)	$ 7,222,792	41.76%	$ 3,016,111	8.00%	$ 241,289	39.00%	$ 1,176,283	13.11%	$ 154,267	$ 395,556
	Support Services	$ 43,594,682	1.50%	$ 652,072	8.00%	$ 52,166	39.00%	$ 254,308	13.11%	$ 33,352	$ 85,518
	TOTAL	**$ 50,817,474**		**$ 3,668,182**		**$ 293,455**		**$ 1,430,591**		**$ 187,619**	**$ 481,073**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	**Department**	A	B	C = A x B	D	E = C x D	F	G = F x C	EFTE	H = G x EFTE	I = E + H
41. Total Compensation and Benefits	CEO (10000)	$ 12,954,780	5.00%	$ 647,739	30.00%	$ 194,322	0.00%	$ -	31.09%	$ -	$ 194,322
	Corporate Controller (10047)	$ 15,939,163	1.05%	$ 167,891	0.00%	$ -	100.00%	$ 167,891	31.09%	$ 52,194	$ 52,194
	Total Compensation (10091)	$ 3,829,233	86.60%	$ 3,316,037	3.00%	$ 99,481	79.00%	$ 2,619,669	31.09%	$ 814,403	$ 913,884
	Pension & Benefits (10096)	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	31.09%	$ -	$ -
	Corporate HR (10092)	$ 3,946,946	14.58%	$ 575,596	8.00%	$ 46,048	47.00%	$ 270,530	31.09%	$ 84,102	$ 130,150
	People and Partners (10094)	$ 3,898,081	22.22%	$ 866,240	10.00%	$ 86,624	55.00%	$ 476,432	31.09%	$ 148,113	$ 234,737
	Support Services	$ 43,594,682	2.15%	$ 937,349	7.65%	$ 71,724	63.42%	$ 594,434	31.09%	$ 184,798	$ 256,522
	TOTAL	**$ 84,162,885**		**$ 6,510,852**		**$ 498,199**		**$ 4,128,956**		**$ 1,283,611**	**$ 1,781,809**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	**Department**	A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x Users	I = E + H
8. Consolidation and Planning System Technical Support (Khalix)	CIO (10001)	$ 4,030,466	5.62%	$ 226,431	0.00%	$ -	100.00%	$ 226,431	33.66%	$ 76,221	$ 76,221
	EFS Support (10040)	$ 701,602	27.25%	$ 191,170	2.00%	$ 3,823	70.00%	$ 133,819	33.66%	$ 45,046	$ 48,870
	Corporate Controller (10047)	$ 15,939,163	1.05%	$ 167,891	0.00%	$ -	100.00%	$ 167,891	33.66%	$ 56,515	$ 56,515
	Support Services	$ 43,594,682	0.47%	$ 204,668	0.65%	$ 1,337	90.20%	$ 184,620	33.66%	$ 62,147	$ 63,483
	TOTAL	**$ 66,689,898**		**$ 790,160**		**$ 5,160**		**$ 712,761**		**$ 239,929**	**$ 245,089**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
9. Corporate Compliance	CEO (10000)	$ 12,954,780	2.22%	$ 287,884	25.00%	$ 71,971	0.00%	$ -	15.75%	$ -	$ 71,971
	CFO (10045)	$ 3,719,515	3.52%	$ 130,837	10.00%	$ 13,084	0.00%	$ -	15.75%	$ -	$ 13,084
	Corporate Controller (10047)	$ 15,939,163	1.00%	$ 159,008	0.00%	$ -	63.00%	$ 100,175	15.75%	$ 15,778	$ 15,778
	Total Compensation (10091)	$ 3,829,233	6.19%	$ 236,860	0.00%	$ -	100.00%	$ 236,860	15.75%	$ 37,305	$ 37,305
	Corporate HR (10092)	$ 3,946,946	1.04%	$ 41,114	0.00%	$ -	90.00%	$ 37,003	15.75%	$ 5,828	$ 5,828
	People and Partners (10094)	$ 3,898,081	5.56%	$ 216,560	0.00%	$ -	100.00%	$ 216,560	15.75%	$ 34,108	$ 34,108
	Support Services	$ 43,594,682	0.26%	$ 115,178	7.93%	$ 9,136	55.08%	$ 63,439	15.75%	$ 9,992	$ 19,128
	TOTAL	**$ 87,882,401**		**$ 1,187,441**		**$ 94,191**		**$ 654,037**		**$ 103,011**	**$ 197,202**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
10. Industry Relations & Corporate Social Responsibility	Public and Government Affairs (10072)	$ 16,935,260	31.87%	$ 5,396,951	3.00%	$ 161,909	19.00%	$ 1,025,421	15.75%	$ 161,504	$ 323,412
	People and Partners (10094)	$ 3,898,081	3.33%	$ 129,936	0.00%	$ -	100.00%	$ 129,936	15.75%	$ 20,465	$ 20,465
	Support Services	$ 43,594,682	1.69%	$ 736,503	2.53%	$ 18,660	18.08%	$ 133,154	15.75%	$ 20,972	$ 39,632
	Industry Associations (10023)	$ 15,914	100.00%	$ 15,914	2.53%	$ 403	18.08%	$ 2,877	15.75%	$ 453	$ 856
	TOTAL	**$ 77,398,718**		**$ 7,142,956**		**$ 180,972**		**$ 1,291,388**		**$ 203,394**	**$ 384,365**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
11. Emerging Energy Technology Research	Alternative and Emerging Technology (10106)	$ 5,332,830	82.83%	$ 4,417,092	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Corporate Development and Planning	$ 10,826,264	0.00%	$ 0	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	Support Services	$ 43,594,682	1.62%	$ 707,923	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	TOTAL	**$ 59,753,776**		**$ 5,125,015**		**$ -**		**$ -**		**$ -**	**$ -**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	Non-Union EFTE	H = G x Non-Union EFTE	I = E + H
12. Employee Development	CEO (10000)	$ 12,954,780	8.33%	$ 1,079,565	45.00%	$ 485,804	0.00%	$ -	23.90%	$ -	$ 485,804
	Organizational Effectiveness (10090)	$ 3,004,859	100.00%	$ 3,004,859	5.00%	$ 150,243	53.00%	$ 1,592,575	23.90%	$ 380,612	$ 530,855
	Corporate HR (10092)	$ 3,946,946	5.21%	$ 205,570	0.00%	$ -	27.00%	$ 55,504	23.90%	$ 13,265	$ 13,265
	People and Partners (10094)	$ 3,898,081	3.33%	$ 129,936	20.00%	$ 25,987	40.00%	$ 51,974	23.90%	$ 12,421	$ 38,409
	HR Enterprise Business Solutions (10089)	$ 2,001,904	5.05%	$ 101,106	0.00%	$ -	100.00%	$ 101,106	23.90%	$ 24,164	$ 24,164
	Support Services	$ 43,594,682	1.60%	$ 695,524	14.64%	$ 101,849	39.84%	$ 277,094	23.90%	$ 66,223	$ 168,072
	TOTAL	**$ 69,401,253**		**$ 5,216,561**		**$ 763,883**		**$ 2,078,254**		**$ 496,685**	**$ 1,260,568**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
13. Enterprise IT Program Management	CIO (10001)	$ 4,030,466	57.30%	$ 2,309,593	0.00%	$ -	100.00%	$ 2,309,593	15.75%	$ 363,761	$ 363,761
	IT Planning and Governance (10012)	$ 4,772,072	49.28%	$ 2,351,456	0.00%	$ -	100.00%	$ 2,351,456	15.75%	$ 370,354	$ 370,354
	Support Services	$ 43,594,682	1.96%	$ 853,197	0.00%	$ -	100.00%	$ 853,197	15.75%	$ 134,378	$ 134,378
	TOTAL	**$ 52,397,220**		**$ 5,514,246**		**$ -**		**$ 5,514,246**		**$ 868,494**	**$ 868,494**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
14. Enterprise IT Strategy Planning & Management	CIO (10001)	$ 4,030,466	0.00%	$ -	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	IT Planning and Governance (10012)	$ 4,772,072	50.72%	$ 2,420,616	0.00%	$ -	100.00%	$ 2,420,616	15.75%	$ 381,247	$ 381,247
	People and Partners (10094)	$ 3,898,081	11.11%	$ 433,120	30.00%	$ 129,936	45.00%	$ 194,904	15.75%	$ 30,697	$ 160,633
	Support Services	$ 43,594,682	1.65%	$ 718,809	2.74%	$ 19,719	55.22%	$ 396,927	15.75%	$ 62,516	$ 82,235
	TOTAL	**$ 56,295,302**		**$ 3,572,546**		**$ 149,655**		**$ 3,012,447**		**$ 474,460**	**$ 624,115**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x Users	I = E + H
15. Expense System Management & Technical Support (Oracle iexpense)	CIO (10001)	$ 4,030,466	3.37%	$ 135,858	0.00%	$ -	100.00%	$ 135,858	23.48%	$ 31,905	$ 31,905
	EFS Support (10040)	$ 701,602	6.61%	$ 46,403	1.00%	$ 464	81.00%	$ 37,586	23.48%	$ 8,827	$ 9,291
	Corporate Admin. (10071)	$ 1,544,417	8.05%	$ 124,263	0.00%	$ -	65.00%	$ 80,771	23.48%	$ 18,968	$ 18,968
	Support Services	$ 43,594,682	0.41%	$ 179,983	0.15%	$ 272	82.93%	$ 149,269	23.48%	$ 35,054	$ 35,327
	TOTAL	**$ 49,871,167**		**$ 486,508**		**$ 736**		**$ 403,485**		**$ 94,754**	**$ 95,490**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	Audit Fees	H = G x Audit Fees	I = E + H
16. External Audit Coordination	CFO (10045)	$ 3,719,515	10.05%	$ 373,821	20.00%	$ 74,764	0.00%	$ -	25.69%	$ -	$ 74,764
	Corporate Controller (10047)	$ 15,939,163	0.95%	$ 151,219	0.00%	$ -	44.00%	$ 66,536	25.69%	$ 17,093	$ 17,093
	Audit Services (Calgary) (10050)	$ 2,598,546	3.45%	$ 89,605	0.00%	$ -	0.00%	$ -	25.69%	$ -	$ -
	Support Services	$ 43,594,682	0.18%	$ 77,229	12.16%	$ 9,394	10.83%	$ 8,360	25.69%	$ 2,148	$ 11,542
	TOTAL	**$ 65,851,906**		**$ 691,874**		**$ 84,158**		**$ 74,896**		**$ 19,241**	**$ 103,399**

		Primary Service Allocation									
Service	Department	Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator Users	Common EGD Allocation H = G x Users	Total Primary Service Allocated To EGD I = E + H
18. Financial and Project Accounting System Technical Support (Oracle)	CIO (10001)	$ 4,030,466	17.98%	$ 724,578	0.00%	$ -	100.00%	$ 724,578	23.48%	$ 170,159	$ 170,159
	EFS Support (10040)	$ 701,602	66.14%	$ 464,029	4.00%	$ 18,561	63.00%	$ 292,338	23.48%	$ 68,652	$ 87,214
	Support Services	$ 43,594,682	1.00%	$ 437,752	1.56%	$ 6,836	85.56%	$ 374,520	23.48%	$ 87,952	$ 94,788
	TOTAL	**$ 48,326,750**		**$ 1,626,360**		**$ 25,397**		**$ 1,391,437**		**$ 326,764**	**$ 352,161**

		Primary Service Allocation									
Service	Department	Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator Time	Common EGD Allocation H = G x Time	Total Primary Service Allocated To EGD I = E + H
21. Gas Supply, Storage, and Transportation Strategy	CEO (10000)	$ 12,954,780	3.33%	$ 431,826	0.00%	$ -	100.00%	$ 431,826	0.00%	$ -	$ -
	Support Services	$ 43,594,682	0.18%	$ 80,042	0.00%	$ -	100.00%	$ 80,042	0.00%	$ -	$ -
	TOTAL	**$ 56,780,169**		**$ 511,868**		**$ -**		**$ 511,868**		**$ -**	**$ -**

		Primary Service Allocation									
Service	Department	Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator ACER	Common EGD Allocation H = G x ACER	Total Primary Service Allocated To EGD I = E + H
22. Government Relations	Public and Government Affairs (10072)	$ 16,935,260	7.69%	$ 1,302,712	3.12%	$ 40,653	0.00%	$ -	15.75%	$ -	$ 40,653
	Support Services	$ 43,594,682	0.45%	$ 195,585	2.18%	$ 4,265	0.00%	$ -	15.75%	$ -	$ 4,265
	TOTAL	**$ 77,899,304**		**$ 2,060,059**		**$ 44,917**		**$ -**		**$ -**	**$ 44,917**

		Primary Service Allocation									
Service	Department	Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator Users	Common EGD Allocation H = G x Users	Total Primary Service Allocated To EGD I = E + H
23. HRIS Program Management and Development	CIO (10001)	$ 4,030,466	36.31%	$ 1,463,660	0.00%	$ -	100.00%	$ 1,463,660	31.09%	$ 455,023	$ 455,023
	Pension & Benefits (10096)	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	31.09%	$ -	$ -
	Corporate HR (10092)	$ 3,946,946	10.42%	$ 411,140	0.00%	$ -	100.00%	$ 411,140	31.09%	$ 127,815	$ 127,815
	HRIS Services (10095)	$ 4,698,241	100.00%	$ 4,698,241	0.00%	$ -	100.00%	$ 4,698,241	31.09%	$ 1,460,590	$ 1,460,590
	HR Enterprise Business Solutions (10089)	$ 2,001,904	91.92%	$ 1,840,134	0.00%	$ -	100.00%	$ 1,840,134	31.09%	$ 572,061	$ 572,061
	Support Services	$ 43,594,682	2.91%	$ 1,266,673	0.00%	$ -	100.00%	$ 1,266,673	31.09%	$ 393,783	$ 393,783
	TOTAL	**$ 58,272,240**		**$ 9,679,848**		**$ -**		**$ 9,679,848**		**$ 3,009,273**	**$ 3,009,273**

Service	Department	Primary Service Allocation Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator EFTE	Common EGD Allocation H = G x EFTE	Total Primary Service Allocated To EGD I = E + H
24. Human Resource Advice	CEO (10000)	$ 12,954,780	1.11%	$ 143,942	20.00%	$ 28,788	0.00%	$ -	31.09%	$ -	$ 28,788
	Corporate HR (10092)	$ 3,946,946	57.29%	$ 2,261,271	1.00%	$ 22,613	17.00%	$ 384,416	31.09%	$ 119,507	$ 142,120
	Support Services	$ 43,594,682	1.00%	$ 434,448	2.14%	$ 9,284	15.98%	$ 69,436	31.09%	$ 21,586	$ 30,871
	TOTAL	**$ 64,325,641**		**$ 2,839,661**		**$ 60,686**		**$ 453,852**		**$ 141,094**	**$ 201,779**

Service	Department	Primary Service Allocation Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator Insurance Premiums	Common EGD Allocation H = G x Insurance Premiums	Total Primary Service Allocated To EGD I = E + H
26. Insurance Claims Support, Strategy and Management (Combined)	CFO (10045)	$ 3,719,515	4.02%	$ 149,528	0.00%	$ -	100.00%	$ 149,528	14.20%	$ 21,233	$ 21,233
	Enterprise Risk (10046)	$ 10,938,498	2.13%	$ 232,734	9.00%	$ 20,946	0.00%	$ -	14.20%	$ -	$ 20,946
	Insurance Risk (10051)	$ 1,108,561	100.00%	$ 1,108,561	3.00%	$ 33,257	0.00%	$ -	14.20%	$ -	$ 33,257
	Support Services	$ 43,594,682	1.30%	$ 567,374	3.64%	$ 20,628	10.03%	$ 56,907	14.20%	$ 8,081	$ 28,709
	EPI Charge	$ 14,905,724	0.54%	$ 80,907	3.64%	$ 2,942	10.03%	$ 8,115	14.20%	$ 1,152	$ 4,094
	TOTAL	**$ 74,266,981**		**$ 2,139,104**		**$ 77,773**		**$ 214,550**		**$ 30,467**	**$ 108,240**

Service	Department	Primary Service Allocation Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator FCER	Common EGD Allocation H = G x FCER	Total Primary Service Allocated To EGD I = E + H
28. Investor Services	CEO (10000)	$ 12,954,780	15.56%	$ 2,015,188	15.00%	$ 302,278	0.00%	$ -	13.87%	$ -	$ 302,278
	Investor Relations (10043)	$ 2,423,890	89.01%	$ 2,157,528	0.00%	$ -	15.00%	$ 323,629	13.87%	$ 44,887	$ 44,887
	Treasury (10044)	$ 7,222,792	2.20%	$ 158,743	3.00%	$ 4,762	34.00%	$ 53,973	13.87%	$ 7,486	$ 12,248
	CFO (10045)	$ 3,719,515	8.04%	$ 299,057	5.00%	$ 14,953	0.00%	$ -	13.87%	$ -	$ 14,953
	Corporate Secretarial (10070)	$ 4,423,865	14.61%	$ 646,182	1.00%	$ 6,462	6.00%	$ 38,771	13.87%	$ 5,378	$ 11,839
	Public and Government Affairs (10072)	$ 16,935,260	2.20%	$ 372,204	4.00%	$ 14,888	0.00%	$ -	13.87%	$ -	$ 14,888
	People and Partners (10094)	$ 3,898,081	1.11%	$ 43,312	0.00%	$ -	100.00%	$ 43,312	13.87%	$ 6,007	$ 6,007
	Support Services	$ 43,594,682	12.49%	$ 5,445,857	6.03%	$ 328,484	8.08%	$ 439,790	13.87%	$ 60,999	$ 389,482
	Corporate Secretarial Legal Fees (10024)	$ 1,220,000	100.00%	$ 1,220,000	6.03%	$ 73,588	8.08%	$ 98,523	13.87%	$ 13,665	$ 87,253
	TOTAL	**$ 96,392,865**		**$ 12,358,070**		**$ 745,415**		**$ 997,998**		**$ 138,422**	**$ 883,837**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	Department	A	B	C = A x B	D	E = C x D	F	G = F x C	EFTE	H = G x EFTE	I = E + H
42. Employee and Labour Relations (Combined)	Pension & Benefits (10096)	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	31.09%	$ -	$ -
	Organizational Effectiveness (10090)	$ 3,004,859	0.00%	$ -	0.00%	$ -	0.00%	$ -	31.09%	$ -	$ -
	Corporate HR (10092)	$ 3,946,946	3.13%	$ 61,572	0.00%	$ -	71.00%	$ 87,573	31.09%	$ 27,225	$ 27,225
	Labour Relations (10093)	$ 1,014,064	84.21%	$ 853,949	40.00%	$ 341,579	30.00%	$ 256,185	31.09%	$ 79,643	$ 421,222
	People and Partners (10094)	$ 3,898,081	1.11%	$ 43,312	0.00%	$ -	100.00%	$ 43,312	31.09%	$ 13,465	$ 13,465
	Support Services	$ 43,594,682	0.08%	$ 36,813	32.26%	$ 11,878	38.55%	$ 14,192	31.09%	$ 4,412	$ 16,289
	EGD Charge	$ 1,716,941	0.00%	$ -	32.13%	$ -	38.62%	$ -	31.09%	$ -	$ -
	TOTAL	**$ 57,175,574**		**$ 1,057,416**		**$ 353,457**		**$ 401,261**		**$ 124,744**	**$ 478,201**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	Department	A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
30. Legal Advice	Corporate Secretarial (10070)	$ 4,423,865	21.35%	$ 944,421	1.00%	$ 9,444	15.00%	$ 141,663	15.75%	$ 22,312	$ 31,756
	Executive VP Corporate Law (10078)	$ 3,765,602	30.00%	$ 1,129,681	10.00%	$ 112,968	0.00%	$ -	15.75%	$ -	$ 112,968
	Corporate Law (10077)	$ 5,979,072	64.37%	$ 3,848,598	5.00%	$ 192,430	4.00%	$ 153,944	15.75%	$ 24,246	$ 216,676
	Support Services	$ 43,594,682	3.36%	$ 1,466,011	5.32%	$ 77,931	4.99%	$ 73,170	15.75%	$ 11,524	$ 89,455
	Corporate Law Legal Fees (10020)	$ 600,000	100.00%	$ 600,000	5.32%	$ 31,895	4.99%	$ 29,947	15.75%	$ 4,717	$ 36,612
	EGD Charge	$ 1,716,941	0.76%	$ 13,000	0.00%	$ -	0.00%	$ -	15.75%	$ -	$ -
	EPI Charge	$ 14,905,724	2.96%	$ 441,305	5.32%	$ 23,459	4.99%	$ 22,026	15.75%	$ 3,469	$ 26,928
	TOTAL	**$ 74,985,886**		**$ 8,443,016**		**$ 448,128**		**$ 420,749**		**$ 66,268**	**$ 514,396**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	Department	A	B	C = A x B	D	E = C x D	F	G = F x C	Audit Fees	H = G x Audit Fees	I = E + H
32. Planning, Management & Execution of Internal Audits	CFO (10045)	$ 3,719,515	4.02%	$ 149,528	20.00%	$ 29,906	0.00%	$ -	25.69%	$ -	$ 29,906
	Audit Services (Calgary) (10050)	$ 2,598,546	63.22%	$ 1,642,759	4.00%	$ 65,710	10.00%	$ 164,276	25.69%	$ 42,202	$ 107,912
	Support Services	$ 43,594,682	1.10%	$ 479,102	5.33%	$ 25,559	9.17%	$ 43,913	25.69%	$ 11,281	$ 36,840
	EPI Charge	$ 14,905,724	1.47%	$ 219,382	5.33%	$ 11,704	9.17%	$ 20,108	25.69%	$ 5,166	$ 16,869
	TOTAL	**$ 64,818,467**		**$ 2,490,771**		**$ 132,879**		**$ 228,297**		**$ 58,648**	**$ 191,528**

		Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
Service	Department	A	B	C = A x B	D	E = C x D	F	G = F x C	N/A	H = G x N/A	I = E + H
33. Rate Regulated Entity Support	Treasury (10044)	$ 7,222,792	4.40%	$ 317,485	53.00%	$ 168,267	5.00%	$ 15,874	0.00%	$ -	$ 168,267
	Corporate Controller (10047)	$ 15,939,163	0.59%	$ 93,395	36.00%	$ 33,622	0.00%	$ -	0.00%	$ -	$ 33,622
	Support Services	$ 43,594,682	0.24%	$ 105,859	49.14%	$ 52,015	3.86%	$ 4,090	0.00%	$ -	$ 52,015
	EGD Charge	$ 1,716,941	8.15%	$ 140,000	0.00%	$ -	0.00%	$ -	0.00%	$ -	$ -
	TOTAL	**$ 68,473,577**		**$ 656,739**		**$ 253,904**		**$ 19,964**		**$ -**	**$ 253,904**

		Primary Service Allocation									
Service	Department	Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator Users	Common EGD Allocation H = G x Users	Total Primary Service Allocated To EGD I = E + H
34. Records and Information Management	Enterprise Content Management (10075)	$ 5,821,798	100.00%	$ 5,821,798	0.00%	$ -	100.00%	$ 5,821,798	5.23%	$ 304,287	$ 304,287
	Corporate Law (10077)	$ 5,979,072	20.69%	$ 1,237,049	0.00%	$ -	100.00%	$ 1,237,049	5.23%	$ 64,657	$ 64,657
	Records Management (10079)	$ 1,151,750		$ 1,151,750	0.00%	$ -	100.00%	$ 1,151,750	5.23%	$ 60,198	$ 60,198
	Corporate IT Operations (10009)	$ 702,993	100.00%	$ 702,993	0.00%	$ -	100.00%	$ 702,993	5.23%	$ 36,743	$ 36,743
	Support Services	$ 43,594,682	3.18%	$ 1,386,480	0.00%	$ -	100.00%	$ 1,386,480	5.23%	$ 72,467	$ 72,467
	TOTAL	**$ 57,250,295**		**$ 10,300,070**		**$ -**		**$ 10,300,070**		**$ 538,352**	**$ 538,352**

		Primary Service Allocation									
Service	Department	Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator FCER	Common EGD Allocation H = G x FCER	Total Primary Service Allocated To EGD I = E + H
36. Risk Assessment and Management	CEO (10000)	$ 12,954,780	2.22%	$ 287,884	10.00%	$ 28,788	0.00%	$ -	13.87%	$ -	$ 28,788
	Enterprise Risk (10046)	$ 10,938,498	86.17%	$ 9,425,727	5.00%	$ 471,286	11.00%	$ 1,036,830	13.87%	$ 143,808	$ 615,095
	CFO (10045)	$ 3,719,515	4.02%	$ 149,528	10.00%	$ 14,953	0.00%	$ -	13.87%	$ -	$ 14,953
	Corporate Controller (10047)	$ 15,939,163	0.00%	$ 0	0.00%	$ -	0.00%	$ -	13.87%	$ -	$ -
	Audit Services (Calgary) (10050)	$ 2,598,546	6.90%	$ 179,210	7.00%	$ 12,545	18.00%	$ 32,258	13.87%	$ 4,474	$ 17,019
	Support Services	$ 43,594,682	6.91%	$ 3,010,478	5.25%	$ 158,155	10.65%	$ 320,489	13.87%	$ 44,452	$ 202,607
	TOTAL	**$ 96,967,976**		**$ 13,052,828**		**$ 685,727**		**$ 1,389,577**		**$ 192,734**	**$ 878,461**

		Primary Service Allocation									
Service	Department	Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator FCER	Common EGD Allocation H = G x FCER	Total Primary Service Allocated To EGD I = E + H
37. Strategic Planning	CEO (10000)	$ 12,954,780	20.00%	$ 2,590,956	10.00%	$ 259,096	0.00%	$ -	13.87%	$ -	$ 259,096
	Treasury (10044)	$ 7,222,792	0.00%	$ -	0.00%	$ -	0.00%	$ -	13.87%	$ -	$ -
	Enterprise Risk (10046)	$ 10,938,498	2.13%	$ 232,734	16.00%	$ 37,237	0.00%	$ -	13.87%	$ -	$ 37,237
	Support Services	$ 43,594,682	1.54%	$ 669,191	4.72%	$ 31,557	0.00%	$ -	13.87%	$ -	$ 31,557
	TOTAL	**$ 110,640,831**		**$ 6,953,252**		**$ 327,890**		**$ -**		**$ -**	**$ 327,890**

		Primary Service Allocation									
Service	Department	Loaded Department Budget A	Time Allocation to Service B	Primary Service Cost C = A x B	EGD Time Allocation D	Direct EGD Allocation E = C x D	Common Time Allocation F	Total Common Costs G = F x C	Common Allocator ACER	Common EGD Allocation H = G x ACER	Total Primary Service Allocated To EGD I = E + H
38. Supply Chain Management	CFO (10045)	$ 3,719,515	4.02%	$ 149,528	0.00%	$ -	100.00%	$ 149,528	15.75%	$ 23,551	$ 23,551
	Corporate Admin. (10071)	$ 1,544,417	5.75%	$ 88,760	0.00%	$ -	65.00%	$ 57,694	15.75%	$ 9,087	$ 9,087
	Support Services	$ 43,594,682	0.12%	$ 51,611	0.00%	$ -	86.96%	$ 44,882	15.75%	$ 7,069	$ 7,069
	TOTAL	**$ 48,858,615**		**$ 289,899**		**$ -**		**$ 252,104**		**$ 39,706**	**$ 39,706**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Time	H = G x Time	I = E + H
40. Tax Reporting & Planning	Tax Services (Calgary) (10049)	$ 3,162,738	66.93%	$ 2,116,721	1.86%	$ 39,265	2.00%	$ 42,334	1.77%	$ 747	$ 40,013
	CFO (10045)	$ 3,719,515	4.02%	$ 149,528	0.00%	$ -	0.00%	$ -	1.77%	$ -	$ -
	Support Services	$ 43,594,682	1.96%	$ 852,556	1.73%	$ 14,771	1.87%	$ 15,926	1.77%	$ 281	$ 15,053
	EPI Charge	$ 14,905,724	0.09%	$ 13,769	1.73%	$ 239	1.87%	$ 257	1.77%	$ 5	$ 243
	TOTAL	**$ 65,382,659**		**$ 3,132,573**		**$ 54,275**		**$ 58,518**		**$ 1,033**	**$ 55,308**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x Users	I = E + H
43. Portal Suite Operations & Technical Support	Corporate IT Operations (10009)	$ 1,479,996	22.99%	$ 340,229	0.00%	$ -	100.00%	$ 340,229	31.09%	$ 105,770	$ 105,770
	CIO (10001)	$ 4,030,466	12.53%	$ 504,925	0.00%	$ -	100.00%	$ 504,925	31.09%	$ 156,971	$ 156,971
	Support Services	$ 43,594,682	0.50%	$ 219,182	0.00%	$ -	100.00%	$ 219,182	31.09%	$ 68,139	$ 68,139
	TOTAL	**$ 49,105,144**		**$ 1,064,336**		**$ -**		**$ 1,064,336**		**$ 330,881**	**$ 330,881**

Source: Accompanying Schedules A-D to Appendix "A" to the RCAM Confirmation Notice between EI and EGD for the year 2012

Accompanying Schedule to Appendix "A" to the Regulatory Cost allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

General Expense and Direct Charge Breakdown

			Indirect Portion of Direct Charge				
Services	**Total Budget**	**EGD Direct Allocation**	**EI Direct Charge**	**Allocator**	**%**	**EGD Indirect Allocation**	**Total EGD Allocation**
EGD EFS True Up							
Direct EFS Charge (Credit)	$ (2,314,784)	$ (2,314,784)					$ (2,314,784)
Total EFS True Up	$ (2,314,784)	$ (2,314,784)					$ (2,314,784)
General Expenses							
Directors Fees and Expenses	$ 5,370,000		$ 5,370,000	FCER	14%	$ 744,819	$ 744,819
Directors Fees Credit - EGD		$ -					$ -
Total Directors Fees and Expenses	$ 5,370,000	$ -	$ 5,370,000			$ 744,819	$ 744,819
Depreciation - Risk Management System (Usage)	$ 1,278,570	$ 64,951				$ -	$ 64,951
Total General Expenses	$ 6,648,570	$ 64,951	$ 5,370,000			$ 744,819	$ 809,770
Direct Charges							
Insurance Premiums	$ 59,744,528	$ 8,483,868				$ -	$ 8,483,868
EGD Stock Based Compensation	$ 7,549,229	$ 7,549,229				$ -	$ 7,549,229
Total Direct Charges	$ 67,293,757	$ 16,033,097	$ -			$ -	$ 16,033,097
Total Other Charges	**$ 71,627,543**	**$ 13,783,264**	**$ 5,370,000**			**$ 744,819**	**$ 14,528,083**

Source: Accompanying Schedules A-D to Appendix "A" to the RCAM Confirmation Notice between EI and EGD for the year 2012

Accompanying Schedule to Appendix "A" to the Regulatory Cost allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Breakdown of Return on Invested Capital Charge

Net Book Value of Enbridge Inc. Assets (1)	Allocation Mechanism to EGD	Allocation Percentage	EGD Portion of EI Assets	Applicable Rate of Return (2)	Charge to EGD
$ 35,087,973	FCER	14%	$ 4,866,702	7.58%	$ 368,896

Notes
(1) Does not include Work-In-Progress or Intangible Assets
(2) EGD's Weighted Average Cost of Capital (WACC) approved by the Board in EB-2006-0034.

Source: Accompanying Schedules A-D to Appendix "A" to the RCAM Confirmation Notice between EI and EGD for the year 2012

Accompanying Schedule to Appendix "A" to the Regulatory Cost allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Breakdown of EI Support Service Costs

Support Services	**Total Budget**
1. Air Travel for Company Personnel	$ 1,006,263
2. Budgeting & Forecasting	$ 5,959,210
3. Certification of Financial Reporting & Internal Controls	$ 2,083,515
4. Consolidation Accounting	$ 1,096,923
5. Corporate General Accounting	$ 1,897,802
6. Corporate Office Administration	$ 5,129,593
7. Environment, Health & Safety	$ 59,871
8. Financial Projects	$ 278,299
9. Financial Reporting	$ 6,164,755
10. HelpDesk, Network, Infrastructure & Hardware Support	$ -
11. Information System Support Applications	$ 12,475,694
12. Invoice Processing and Payment	$ 191,628
13. IT Project Management & Support	$ 5,355,063
14. IT Software Support & Maintenance	$ 884,595
15. Payroll & Benefits Processing	$ 1,011,472
16. IFRS Service	$ -
Total EI Support Service Costs	**$ 43,594,682**

Source: Accompanying Schedules A-D to Appendix "A" to the RCAM Confirmation Notice between EI and EGD for the year 2012

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Regulatory Cost Allocation Methodology
Service Schedules

Effective January 1, 2012

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

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APPENDIX A. Cost Allocations to EGD

Primary Services

The following tables outline the primary services provided by the Service Provider to EGD. These primary services are agreed to in writing by a representative of EGD.

A primary service is defined as a service provided by the Service Provider to the Service Recipient either as the sole provider where EGD relies solely on EI for this service or as a supplemental provider (where EGD itself performs a component of the required activities of the service). A list of the primary services and the bases of allocation attributable thereto are set out in RCAM.

Each table provides details for:

- The service definition;
- The specific services provided by each Service Provider department;
- The EGD representative responsible for agreeing to the service;
- The EGD cost for the service as calculated in the RCAM model;
- The expected deliverables; and
- The quantity and quality of the service.

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

1. Audit & Accounting Advice

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Audit and Accounting Advice service is responsible for providing EGD with research and advice related to the company's audit and accounting practices. This includes advising on proposed changes relating to accounting guidance and securities regulation requirements and the related business impacts.</td></tr>
<tr><td>Services Identified by Department</td><td><u>Audit Services Department</u>
The Audit and Accounting Advice service is responsible for providing EGD with research and advice related to the company's audit and accounting practices. This includes advising on proposed changes relating to accounting guidance and securities regulation requirements and the related business impacts. The Audit Services Department supports this service by coordinating the collection and dissemination of changes in accounting and audit practices in relation to the statutory and regulatory environments (i.e. CICA, AcSB, FASB, OSC, CPAB, SEC, PCAOB, GAAP and GAAS) and their potential business impacts.

Examples of activities related to the provision of the service include:
Research changes to GAAS as they relate to audit procedures and develop impact assessments
<u>Corporate Controller Department</u>
The Audit and Accounting Advice service is responsible for providing EGD with research and advice related to the company's audit and accounting practices. This includes advising on proposed changes relating to accounting guidance and securities regulation requirements and the related business impacts. The Corporate Controller Department supports this service by researching accounting issues designed to improve corporate knowledge of all new financial reporting requirements and is responsible for managing the implementation of new accounting standards

Examples of activities related to the provision of this service include:
Research changes to GAAP as they relate to accounting policy and develop impact assessments, including recent changes to accounting for rate regulated entities
Restate historical results due to changes in GAAP
Assess changes in business practices and need for changes in accounting policies
Research general accounting and industry trends
Provide advice on specific transactions
Consultation on response to the securities regulator relating to detailed review of EGD's disclosure obligations
<u>Enterprise Security Department</u>
The Audit and Accounting Advice service is responsible for providing the organization with research and advice related to the company's audit and accounting practices. This includes advising EGD on proposed changes relating to accounting guidance and securities regulation requirements and the related business impacts. The Enterprise Security Department supports this service by being responsible for incident prevention policies across the organization with the ability to identify and understand security risks in the business environment, apply the necessary controls to mitigate those risks, and enlist the support of other departments (Risk Management, Internal Audit, Human Resources, etc) in order to mitigate the risks.</td></tr>
</table>

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	Examples of activities related to the provision of the service include: • Define, identify and understand security risks in the business environment of EGD • Monitor and update controls and policies in relation to mitigation of identified risks
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution
Cost of Service	

Department	Service Charge
Audit Services (Calgary)	$16,636
Corporate Controller	$74,634
Enterprise Security	$0
Total	**$91,270**

Expected Deliverables

- Support EGD's audit and accounting infrastructure with accounting research, insights and knowledge

Quantity and Quality of Service

- On demand access to expertise and research and knowledge
- Effective, current accounting policies

Authorized Signature

Nkishinchandani

Mr. Narin Kishinchandani
Vice-President Finance
Enbridge Gas Distribution

Mar 2, 2012
Date

2. Board of Directors Support

Service Description	
Service Definition:	The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees.

Services Identified by Department	**<u>CEO Department</u>**
	The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The CEO Department supports this service by providing representation and a direct line of communication with the EGD Board.
	
	Examples of activities related to the provision of the service include:
	• Maintain a seat on the EGD Board of Directors
	• Keep the EGD Board informed on all relevant company issues; including receiving guidance from board on course of action and incorporating input into the strategic direction of the company
	• Communicating strategies for executive and board compensation
	• Provide active participation and leadership to board meeting preparation activities; including the development of presentations and other relevant material
	• Act as the central point of contact for Directors on issues and concerns
	
	<u>CFO Department</u>
	The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial affairs.
	
	Examples of activities related to the provision of the service include:
	• Liaise between Finance Departments and the Board of Director's Audit Finance and Risk Committee
	
	<u>People and Partners Department</u>
	The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The People and Partners Department supports this service by coordinating and providing the required administrative and consulting services that the EGD board requires as well as acting as a liaison between the Board of Directors and Board Committee.
	
	Examples of activities related to the provision of the service include:
	• Provide EGD representation on various board committees
	  o Social Responsibility Committee
	    ▪ Prepare agenda and documents for the chairperson
	    ▪ Prepare formal EH&S report
	    ▪ Prepare incident reports
	    ▪ Prepare CSR annual report
	  o Governance Committee

- Assist with board committees
- Involved in the appointment of directors and officers to EGD Board
- Involved with whistle-blower protection and code of conduct

o Human Resources and Compensation Committee

- Assist board committee on compensation and succession planning
- Recommend compensation for EGD
- Responsible for recommendations for STIP and LTIP
- Responsible for prudence and due diligence on compensation related matters
- Engage consultants to provide independent counsel and advice
- Provide guidance and advice to EGD related to succession planning and development plans

- Responsible for the community investment program
- Coordinate the production and distribution of materials for EGD Board and their supporting committees
- Coordinate and provide administrative and advisory consulting services to the EGD Board and its Committee
- Inform, assist and advise the EGD Board and its committee on security matters and community issues
- Manage the services of external consultants to the Board
- Develop programs and policies related to governance and corporate social responsibility issues
- Coordinate the administration of all travel and service allowances for the Board
- Oversee all Director fees and expenses budgeting and administration

Corporate Secretarial Department

The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committee. The Corporate Secretarial Department supports this service by providing governance, legal, paralegal and administrative services in respect of EGD Board and supporting committee activities.

Examples of activities related to the provision of the service include:

- Activities for EGD Board of Directors
  - Coordinate communication between Board and Executive Management
  - Provide and manage legal services for Board and Committee (e.g. financial statement certification)
  - Proactively develop policies and programs related to governance issues
    - Directors and officers liability insurance
    - Maintenance and administration of the Directors' compensation program
    - Board and committee evaluations
    - Management discussion and analysis
    - Board and committee membership
  - Manage processes and relationships related to maintaining a public entity
    - Public listings and filings
    - Oversight of transfer agents

Corporate Human Resources Department

The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committee. The Corporate Human Resource Department supports this service by providing HR expertise.

Examples of activities related to the provision of the service include:

- Provide specialized resources for guiding and conducting work in the following areas
  - Governance – Board, Human Resources Compensation Committee, Executive Compensation, Pension Design

Pension & Benefits Department

The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committee.. The Pension & Benefits Department supports this service by providing pension, benefits and governance advice services to EGD Board of Directors and its Committees.

Examples of activities related to the provision of the service:

- Support to the Human Resources & Compensation Committee and Governance Committee
  - Coordinate meeting agendas and the dissemination of support material
  - Develop committee proposals, recommendations and guidance on further approvals
  - Coordinate the dissemination of decisions and oversee the implementation of those decisions
  - Provide orientation services as to role, policies and responsibilities of new and existing committee members
- Develop the policies related to the process, implementation and administration of Board of Directors allowances

Total Compensation Department

The Board of Directors Support service is responsible for providing lines of communication between EGD Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committee. The Total Compensation Department supports this service by providing compensation and governance advice services to the EGD Board of Directors and its Committee.

Examples of activities related to the provision of the service:

- Support to the Human Resources & Compensation Committee and Governance Committee
  - Coordinate meeting agendas and the dissemination of support material
  - Develop committee proposals, recommendations and guidance on further approvals
  - Coordinate the dissemination of decisions and oversee the implementation of those decisions
  - Provide orientation services as to role, policies and responsibilities of new and existing committee members
- Develop the policies related to the process, implementation and administration of Board of Directors allowances

HR Enterprise Business Solutions Department

The Board of Directors Support service is responsible for providing lines of communication between various Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The HR Enterprise Business Solutions Department supports this service by providing support to the talent management department in providing Board of Director Support.

Examples of activities related to the provision of the service:

- Through consultation with HR - develop the data definition of data points on the Board of Directors reporting materials
- Provide data to the Talent Management Department for reporting to the Board of Directors
- Make recommendations for improvement on data delivery
- Provide back-up data/materials for board presentation

New Ventures Department

The Board of Directors Support service is responsible for providing lines of communication between various Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The New Ventures Department supports this service by coordinating and providing the required administrative and consulting services that the Board requires as well as acting as a liaison between the Board Committee.

Examples of activities related to the provision of the service include:

- Coordinate communication between Board and Executive Management for our renewable and clean energy opportunities
- Developing new initiatives and investigating renewable and clean energy opportunities
- Advice and support to assess the commercial viability of our renewable and clean energy markets, and other related investment opportunities

Executive VP Corporate Law Department

The Board of Directors Support service is responsible for providing lines of communication between various Board of Directors and company leaders. This service also includes all preparation activities for EGD Board of Director meetings and associated Board committees. The Executive VP Corporate Law Department supports this service by providing governance, compliance, legal and paralegal services and advice in respect of Board and supporting committee activities.

Examples of activities related to the provision of the service include:

- Activities for EGD Board of Directors
    - Responsible for all policies and processes of corporate governance and executive/board interface
    - Coordinate communication between Board and Executive Management on enterprise wide compliance program, involving designing company compliance policies and programs, overseeing, monitoring and investigation efforts and reporting to senior management and the Board of Directors
    - Provide and manage legal advice for Board and Committees
    - Ensures that practices, policies and records of the Boards of Directors meet executive, legal and corporate governance requirements
    - Secure a leadership position for the Board/Corporation.

- Organize and attend Board and Committee meetings and prepares meeting materials and minutes.
- Coordinates all subsidiary corporate secretarial work as consistent with governance, legal and corporate office requirements;
- Proactively develop policies and programs related to governance issues
  - Directors and officers liability insurance
  - Maintenance and administration of the Directors' compensation program
  - Board and committee evaluations
  - Disclosure issues
  - Board and committee membership

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$290,619
CFO	$28,330
People and Partners	$284,584
Corporate Secretarial	$95,023
Corporate HR	$15,380
Pension & Benefits	$0
Total Compensation	$49,879
HR Enterprise Business Solutions	$5,553
New Ventures	$0
Executive VP Corporate Law	$0
Total	**$769,368**

Expected Deliverables

- Support for the Board members with relevant information for decision making focused on EGD's regulatory environment, business objectives, strategies, financial and operational health as well as general market conditions and business improvement opportunities

Quantity and Quality of Service

- Achievement of the ROE prescribed by the Regulator, at a minimum

Authorized Signature

Nkishinchandani

Mr. Narin Kishinchandani
Vice-President Finance
Enbridge Gas Distribution

Mar 2, 2012
Date

3. Business & Economic Financial Analysis

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Business and Economic Financial Analysis service provides financial modeling and analysis expertise to support the assessment of business development investment opportunities as and when required, to complement the work of Strategy, Research and Planning Group at EGD.</td></tr>
<tr><td>Services Identified by Department</td><td><u>Investment Review Department</u>
The Business and Economic Financial Analysis service provides financial modeling and analysis expertise to support the assessment of business development investment opportunities. The Investment Review Department supports this service by providing financial modeling and analysis expertise to support the assessment of investment opportunities, as and when required, to complement the work of Strategy, Research and Planning Group at EGD.

Examples of activities related to the provision of the service include:
• Advice and support to set the standards, policies, frameworks, criteria and process for evaluating investment opportunities
• Advice and support to assess the commercial viability of emerging operational technologies, markets and other related investment opportunities
• Evaluate potential deal structures and ownership mechanisms relevant to EGD
• Provide guidance on financial modeling and analysis activities and support process for securing Board approval (if required) related to investment opportunities
• Provide research and analysis support to optimize gas supply and storage requirements
• Advice and support to review post-project capital expenditures to determine potential areas for improvement; includes dissemination of lessons learned to the EGD executive team
• Support corporate risk and project specific risk assessments including identifying risks and threats and supporting impact analysis

<u>Corporate Development and Planning Department</u>
The Business and Economic Financial Analysis service provides financial modeling and analysis expertise to support the assessment of business development investment opportunities. The Corporate Development and Planning Department supports this service by providing financial modeling and analysis expertise to support the assessment of investment opportunities, as and when required, to complement the work of Strategy, Research and Planning Group at EGD.

Examples of activities related to the provision of the service include:
• Advice and support to set the standards, policies, frameworks, criteria and process for evaluating investment opportunities
• Advice and support to assess the commercial viability of emerging operational technologies, markets and other related investment opportunities
• Evaluate potential deal structures and ownership mechanisms relevant to EGD
• Provide guidance on financial modeling and analysis activities and support process for securing Board approval (if required) related to investment opportunities</td></tr>
</table>

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	• Provide research and analysis support to optimize gas supply and storage requirements • Advice and support to review post-project capital expenditures to determine potential areas for improvement; includes dissemination of lessons learned to the EGD executive team • Support corporate risk and project specific risk assessments including identifying risks and threats and supporting impact analysis
Service Recipient:	Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution
Cost of Service	
	see table below
Expected Deliverables	
	• Support for Strategy, Research and Planning Group and EGD's management with relevant analytical models for decision making
Quantity and Quality of Service	
	• To complement the work of Strategy, Research and Planning Group • On demand access to expertise and reliable analysis • Analyze opportunities relevant to EGD
Authorized Signature	
	Mr. Arunas Pleckaitis Vice-President Business Development & Customer Strategy Enbridge Gas Distribution Mar 2/12 Date

Department	Service Charge
Investment Review	$0
Corporate Development and Planning	$0
Total	**$0**

4. Business Development

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation.</td></tr>
<tr><td>Services Identified by Department</td><td><u>CEO Department</u>
The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The CEO Department supports this service by providing leadership, guidance and approvals to large projects.

Examples of activities related to the provision of the service include:
Active participation in concept definition and development, including support of analysis activities
Provide review of projects throughout business case development stages, including provision of final approval
Set and monitor project performance metrics, progress monitoring, and issue resolution
Provide project sponsorship and leadership to project teams as required
Monitor business development activities to ensure alignment to long range plan
<u>CFO Department</u>
The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The CFO Department supports this service by providing leadership and guidance on the financial aspects of all business development activities. In addition, the CFO Department is responsible for final sign-off on all business development financial analysis.

Examples of activities related to the provision of the service include:
Active participation in concept definition and development, including support of analysis activities
Provide review of projects throughout business case development stages, including provision of final financial approval
<u>Corporate Human Resources Department</u>
The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Corporate Human Resources Department provides support to this service by conducting due diligence and coordinating the workforce integration and divestiture efforts.</td></tr>
</table>

Examples of activities related to the provision of the service include:

- Conduct due diligence research, impact assessments, support bid development, integration and transition planning
- Integration process development for mergers and acquisitions

Corporate Law Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Corporate Law Department supports this service by providing legal services to specific EGD projects and business development initiatives.

Examples of activities related to the provision of the service include:

- Providing legal advice related to:
    - Corporate or asset acquisitions
    - Obtaining regulatory approvals
    - Managing the due diligence process
    - Contract negotiation and review

Alternative and Emerging Technology Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Alternative and Emerging Technology Department supports this service by identifying investment opportunities and subsequently coordinating the evaluation and execution of opportunities.

Examples of activities related to the provision of the service include:

- Identify business improvement opportunities in Ontario (e.g. new technology deployment, geographic expansion, greenfield development, mergers, acquisitions and partnerships)
- Coordinate the required business and financial analysis required to evaluate investment opportunities and identify alternative strategies
- Implement deal strategies and structures, negotiations and other related aspects of investment opportunities
- Prepare presentations and other required material related to the investment approval process
- Draft, negotiate, document and finalize investment commercial terms and execute transactions
- Coordinate investment transition (if required) to operating groups
- Coordinate business development activities with outside stakeholders
- Manage any investments made with 3rd parties and coordinate the operations and management of these initiatives

Labour Relations Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Labour Relations Department supports this service by providing due diligence activities and integration expertise when unionized employees may be impacted.

Examples of activities related to the provision of this service include:

- Lead and co-ordinate the development of a Labour Relations strategy for business development initiatives
- Provide support and guidance in the due diligence and integration of an acquisition or merger
    - Review existing collective bargaining contracts
    - Liaise with union leadership
    - Coordinate union negotiations
    - Lead, coordinate and facilitate any workforce changes that arise out of mergers, acquisitions and divestitures

Risk Insurance Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Risk Insurance Department supports this service by providing qualified insurance expertise to support projects with material impacts on insurance requirements and costs. Projects include Mergers and Acquisitions and significant asset purchases or divestitures.

Examples of activities related to the provision of the service include:

- Develop insurance cost projections based on changes in assets, people, and nature of business
- Support scenario analysis through identification of insurance cost impact of material changes to business operations

Corporate Controller Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Corporate Controller Department supports this service by providing analytical financial support.

Examples of activities related to the provision of this service include:

- Provide accounting expertise, deal structuring, due diligence support, coordination of external accounting advisors, and financial model review

Public and Government Affairs Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Public and Government Affairs Department provides support to this service by providing advice relating to internal and external communications and for coordinating news releases and other communications.

Examples of activities related to the provision of the service include:

- Assist with development of communication plans for project specific activities/projects (e.g. mergers, acquisition, divestitures and partnerships and new ventures).

Investment Review Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Investment Review Department supports this service by establishing the process for identifying investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities globally.

Examples of activities related to the provision of the service include:

- Coordinate the required business and financial analysis required to evaluate investment opportunities and identify alternative strategies
- Provide advice, guidance, and execution expertise for determining deal strategies and structures, negotiations and other related aspects of investment opportunities
- Draft, negotiate, document and finalize investment commercial terms and execute transactions
- Coordinate business development activities with outside stakeholders

<u>Corporate Development and Planning Department</u>

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Corporate Development and Planning Department supports this service by establishing the process for identifying investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities globally.

Examples of activities related to the provision of the service include:

- Identify business improvement opportunities in Ontario (e.g. geographic expansion, mergers, acquisitions, divestitures and partnerships)
- Coordinate the required business and financial analysis required to evaluate investment opportunities and identify alternative strategies
- Provide advice, guidance, and execution expertise for determining deal strategies and structures, negotiations and other related aspects of investment opportunities
- Prepare presentations and other required material related to the investment approval process
- Draft, negotiate, document and finalize investment commercial terms and execute transactions
- Coordinate investment transition (if required) to operating groups
- Coordinate business development activities with outside stakeholders
- Manage any investments made with 3rd parties and coordinate the operations of these initiatives

<u>Tax Services Department</u>

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Tax Services Department supports this service by providing and coordinating tax advice to business development activities.

Examples of activities related to the provision of the service include:

- Provide tax analysis, structure and modeling expertise on identified initiatives
- Provide support and guidance in the due diligence process

Pension & Benefits Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Pension & Benefits Department supports this service by providing due diligence support for pension and benefit related analysis.

Examples of activities related to the provision of the service include:

- Coordinate pension and benefit impact on mergers, acquisitions and divestiture activities
- Conduct due diligence research, impact assessments, support bid development, integration and transition planning
- Integration process development for mergers and acquisitions

HR Enterprise Business Solutions Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The HR Enterprise Business Solutions Department provides support to this service by coordinating business requirements for Corporate HR.

Examples of activities related to the provision of the service include:

- Coordinate and gather requirements for Corporate HR for EGD's technology related initiatives ensuring all new and add-on opportunities are fully thought out and measured for value
- Manage solution documentation for Enterprise technology initiatives (i.e. upgrade to PeopleSoft) for the benefit of EGD

New Ventures Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The New Ventures Department supports this service by identifying investment opportunities within renewable and clean energy sources of opportunity and subsequently coordinating the evaluation and execution of these opportunities.

Examples of activities related to the provision of the service include:

- Identify business improvement opportunities in Ontario (e.g. geographic expansion, mergers, acquisitions, divestitures and partnerships)
- Provide advice, guidance, and execution expertise for determining deal strategies and structures, negotiations and other related aspects of investment opportunities
- Lead or participate in the EGD investment approval process
- Draft, negotiate, document and finalize investment commercial terms and execute transactions
- Coordinate business development activities with outside stakeholders

- Prepare presentations and other required material related to the investment approval process
- Coordinate the required business and financial analysis required to evaluate investment opportunities and identify EGD renewable and clean energy strategies
- Coordinate investment transition (if required) to operating groups
- Manage any investments made with 3rd parties and coordinate the operations and management of these initiatives

Executive VP Corporate Law Department

The Business Development service is responsible for establishing the process for identifying business improvement investment opportunities and subsequently coordinating and advising on the evaluation and execution of opportunities. Examples of business development activities include asset purchases, company mergers, acquisitions, divestitures, greenfield projects and partnership formation. The Executive VP Corporate Law Department supports this service by providing executive level legal expertise and guidance as well as overall direction for significant EGD projects and business development initiatives.

Examples of activities related to the provision of the service include:

- Providing legal advice related to:
  - Asset acquisitions
  - Obtaining regulatory approvals
  - Managing the due diligence process
  - Contract negotiation and review
  - Preparation of legal documents to complete transactions

Service Recipient: Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$291,407
CFO	$38,980
Corporate Human Resources	$0
Corporate Law	$88,197
Alternative and Emerging Technology	$0
Labour Relations	$125,862
Risk Insurance	$0
Corporate Controller	$92,071
Public & Government Affairs	$100,401
Investment Review	$0
Corporate Development and Planning	$0
Tax Services	$0
Pension & Benefits	$0
HR Enterprise Business Solutions	$0
New Ventures	$0
Executive VP Corporate Law	$0
Total	**$736,918**

Expected Deliverables

- Identify, evaluate and close merger, acquisition and/or divestiture deals for the benefit of EGD using leverage and expertise EGD would not have as a standalone entity

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	• Align business development to EGD's strategic plan
Quantity and Quality of Service	
	• Periodic beneficial acquisitions
Authorized Signature	
	Mr. Arunas Pleckaitis Vice-President Business Development & Customer Strategy Enbridge Gas Distribution MAR. 02/12 Date

5. Capital Market Financing & Access

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets.</td></tr>
<tr><td>Services Identified by Department</td><td>
<u>CEO Department</u>
The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The CEO Department supports this service by providing leadership to the design process of the financing strategy, maintaining investment community contacts, and supporting due diligence efforts.

Examples of activities related to the provision of the service include:

Provide leadership to the development and maintenance of the optimal capital structure and financing strategy
Maintain banking, fixed income, credit agency, and investment banking relationships
Provide guidance to Treasury and CFO on negotiation of terms for large debt or equity issues
Support due diligence efforts conducted by equity/debt issuers prior to receiving financing

<u>CFO Department</u>
The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The CFO Department supports this service by leading the development of the financing strategy, maintaining investment community contacts, participating in financing negotiations, certifying financial statements and supporting due diligence efforts.

Examples activities related to the provision of the service include:

Lead the development of the capital structure and financing strategy
Maintain banking, fixed income, credit agency, and investment banking relationships
Provide guidance on capital structure to Treasury Group and other departments
Lead contract negotiations for large debt or equity issues
Support due diligence processes for equity/debt issues
Ensure investment dealer performance on capital market transactions is monitored and evaluated
Develop Annual Financing Plan in support of the long range plan

<u>Investor Relations Department</u>
The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The Investor Relations Department supports this service by developing and maintaining investment community contacts.

Examples of activities related to the provision of the service include:

Maintain contacts in the investment community for future debt or equity issues
Conduct research on activities, market conditions, competitive issues, and other specific issues which could impact access to capital
Act as an inside analyst to monitor how the company is perceived by

</td></tr>
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stakeholders (i.e. valuation of company)
- Manage 3rd party service contracts for research and other investment related information

Treasury Department

The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The Treasury Department supports this service by defining long-term financing requirements and developing and executing financing strategies in the bank and capital markets.

Examples of activities related to the provision of the service include:
- Develop schedule of debt and equity financing process, including preparation of projections and analysis, and liaison with tax, regulatory and accounting
- Monitor and update financing schedule based on changing internal requirements and external market conditions
- Prepare and file all required regulatory and securities documents for new financing activities
- Negotiate terms and rates for any capital raised in the market
- Maintain and lead credit rating agency, banking, fixed income, and investment banking relationships and presentations

Corporate Secretarial Department

The Capital Market Financing and Access service provides support to the process of raising capital (both debt and equity) and maintaining access to capital markets. The Corporate Secretarial Department supports this service by providing legal, paralegal and administrative services

Examples of activities related to the provision of the service include:
- Support the operations of EGD with legal advice and support in the following areas
  - Financing, credit facilities and tax issues
  - Financing documents (Financials, MD&A, press releases, prospectuses and annual information of the corporation)

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$157,595
CFO	$182,933
Investor Relations	$80,379
Treasury	$520,278
Corporate Secretarial	$78,988
Total	**$1,020,173**

Expected Deliverables

- Provide access to Capital Markets (Debt and Equity)
- Monitor and maintain an appropriate capital structure for EGD
- Provide lower cost financing to EGD than it would be able to achieve as a standalone entity

Quantity and Quality of Service

- Continuous Access to funds
- On demand access to expertise
- Low cost financing

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Authorized Signature		
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution	Mar 2/2012 Date

6. Cash Management & Banking

Service Description

Service Definition: The Cash Management and Banking service determines the optimal short-term cash requirements and executes the supporting daily banking transactions. This includes responsibility for managing short-term liquidity and cash holdings.

Services Identified by Department

Treasury Department

The Cash Management and Banking service determines the optimal short-term cash requirements and executes the supporting daily banking transactions. This includes responsibility for managing short-term liquidity and cash holdings. The Treasury Department supports this service by assuming responsibility for all operational support required to ensure short-term liquidity requirements are met.

Examples of activities related to the provision of the service include:

- Forecast the short term liquidity requirements to optimize the Company's cash balances
- Establish and maintain the Company's bank accounts, banking relationships, and bank credit facilities to support liquidity needs
- Coordinate changes to banking services and interactive processes
- Coordinate large scale accounts payables/receivables transactions
- Manage settlement of risk management vehicles, including those for foreign exchange, interest rate and commodity risk
- Manage investment of surplus funds for short-term appreciation
- Manage the daily operations of the Company's commercial paper program and credit facility borrowings
- Coordinate EGD transactions
  - Calculate invoice amounts and oversee payments
  - Monitoring and managing to identified capital structures
  - Directing internal and external interest and principal payments
- Monitor and report on compliance requirements for debt facilities, regulatory and internal policies
- Administer access to bank accounts and bank reporting systems
- Update and maintain the treasury management reporting system (TMS) with money market and derivative transactions
- Manage the interface of treasury transactions from the TMS to the general ledger for financial reporting purposes.

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Treasury	$481,073
Total	**$481,073**

Expected Deliverables

- Provide access to cash, credit and banking facilities for EGD
- Forecast, monitor and maintain short-term liquidity requirements
- Perform transactional support
- Provide lower cost facilities to EGD than it would be able to achieve as a standalone entity

Quantity and Quality of Service

- On demand access to expertise
- Low Cost borrowing facilities
- Accuracy of transactional data

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Authorized Signature		
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution	Mar 2, 2012 Date

7. Consolidation and Planning System Technical Support (Khalix)

Service Description	
Service Definition:	The Consolidation and Planning System Technical Support (Khalix) service is responsible for the technical support and administration of the consolidation and planning system (Khalix). The Khalix consolidation and planning system consists of three instances used for consolidating the actual results, conducting the enterprise-wide budgeting and forecasting process on an annual basis (ABF), budgeting and forecasting process on a 5 year basis (LRP) and an instance specifically for project budgeting and forecasting (Ensight).
Services Identified by Department	**<u>CIO Department</u>** The Consolidation and Planning System Technical Support (Khalix) service is responsible for the technical support and administration of the Enbridge consolidation and planning system (Khalix). The CIO Department supports this service by providing leadership and management to IT resources providing services: IT System Analysts, IT DBA resources, IT Infrastructure resources, and IT contract resources. Responsible for overseeing all IT related activities from day-to-day technical support to strategic planning for Enterprise Financial Systems (Khalix). Examples of activities related to the provision of this service include: • Ensure Khalix applications are effectively managed. • Assist senior business leadership in terms of IT process changes, business process changes, incremental infrastructure, data, and support processes through interaction with the EFS Governance Committee, representing executive finance and IT management from across Enbridge. • Establish and maintain effective communication and relationship with systems' vendors to ensure prompt and cost efficient vendors support. • Develop, coach and mentor EFS Strategy and Services employees and contractors • Drive the implementation and compliance to quality assurance procedures, standards for process design, documentation, configuration changes, functionality enhancements, and a release management strategy to protect the integrity and reliability of financial data. • Proactively gather and make recommendations regarding complex intelligence from across Enbridge and externally to assess immediate and future impacts on EFS applications, processes, and priorities. • Establish and maintain an effective external network with appropriate application user groups, industry groups, and business partners to share knowledge, gain intelligence, learn cost avoidance strategies, understand alternatives and trends to anticipate, plan, and ensure continuing operational excellence in the support of EGD's evolving business needs. • Reporting & Analysis o Provision of standard reports o Ad hoc report generation / queries o Augment, add, or remove reporting requirements • Technical Support o Interface management o System configurations, customization or enhancements o Release management o Provide back up system support to EFS support group o Manage development life cycle o Monitor system performance

- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

EFS Strategy and Services Department

The Consolidation and Planning System Technical Support (Khalix) service is responsible for the technical support and administration of the Enbridge consolidation and planning system (Khalix). The EFS Strategy and Services Department supports this service by providing technical expertise and assuming responsibility for providing user training, support, system maintenance, customization and enhancements.

Examples of activities related to the provision of this service include:

- Manage client relationships and communication through enterprise-wide committees, of which EGD is a member (Governance Committee, Stakeholder Advisory Group), the EFS team and other stakeholders
- Lead the strategic planning process in relation to efficiency and effectiveness of EFS applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User (incl. super user / power user) training & communication
  - Change management
  - Master file maintenance
  - System configurations, customization or enhancements
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

Corporate Controller Department

The Consolidation and Planning System Technical Support (Khalix) service is responsible for the technical support and administration of the consolidation and planning system (Khalix). The Corporate Controller Department supports this service by providing end user training and support services for the consolidations and budgeting modules

Examples of activities related to the provision of this service include:

- Maintain Khalix training program
- Receive and respond to Khalix user issues
- Provide end user expertise supporting module enhancements, implementations, and customizations testing

Service Recipient: Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$85,514
EFS Strategy and Services	$88,146
Corporate Controller	$71,429
Total	**$245,089**

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Expected Deliverables	
	• Ensure availability of the infrastructure and financial information contained within the Consolidation and Planning System (Khalix) to support long and short term planning in support of EGD management in decision making • Provide user support as required • Ensure availability of technical support and administration. • Ensure availability of a system that follows a diligent process of request prioritization, including assessing cost, resources, systems impacts, and business value to determine which requests will go forward. • Ensuring that EGD is up to date with application market developments in industry. • EGD requires a service that provides timely access to relevant Khalix information. This includes the delivery of OLAP reporting, canned reports, and custom reports.
Quantity and Quality of Service	
	• Continuous and uninterrupted access to Khalix system • Accuracy and integrity of data • On demand user support • Ensuring a consolidation and planning system that is adequately supported from a technical perspective. Including performance management, release management, service management and change management of the entire Khalix system, including interfaces. • Effective and efficient support for Khalix. • Ensure that the system is aligned with the goals and objectives of EGD and is driven by a relevant governance structure. • Ensuring an effective relationship with the Khalix vendor • Ensuring availability of competent staff • Compliance with all relevant best practices (e.g. ITIL, COSO) to maintain system integrity and reliability.
Authorized Signature	
RB	Mr. Henry Wong Director Information Technology Enbridge Gas Distribution Mar. 7, 2012 Date

8. Corporate Compliance

Service Description	
Service Definition:	The Corporate Compliance service is responsible for developing the corporate governance structure and policies.
Services Identified by Department	**<u>CEO Department</u>** The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The CEO Department supports this service by providing senior leadership, overall management guidance and advice regarding financial and operational affairs. Examples of activities related to the provision of the service include: • Approval and communication of policies and controls (i.e. capital spending, operating spending, Treasury Authorized Limits Policy, Risk management policies, etc.) • Provides ultimate responsibility for all personnel, safety & environmental, and regulatory policy issues • Provides ultimate responsibility for governance of the organization with respect to ensuring the proper procedures, policies, processes, people and culture to be successful **<u>CFO Department</u>** The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding financial affairs. Examples of activities related to the provision of the service include: • Approval and communication of policies and controls (i.e. capital spending, operating spending, Treasury Authorized Limits Policy, Risk management policies, etc.) • Identification and resolution of financing concerns **<u>People and Partners Department</u>** The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The People and Partners Department supports this service by assuming responsibility for developing the necessary corporate governance structure and supporting policies. Examples of activities related to the provision of the service include: • Define the governance structure of EGD • Monitor and update compliance to changes in corporate governance standards • Assume compliance on Code of Conduct, disclosure documents, etc. **<u>Corporate Controller Department</u>** The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The Corporate Controller Department supports this service by ensuring alignment and adherence to accounting standards. Examples of activities related to the provision of this service include: • Coordinate and monitor EGD's accounting functions to maintain alignment with industry practices • Design and implement accounting policies (i.e. include the Spending

Authorities Policy, IT Capitalization Policy, and Deferred Cost Policy)

Corporate Human Resources Department

The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The Corporate Human Resources Department supports this service by providing human resources expertise, monitoring and ensuring compliance to regulatory and shareholder requirements.

Examples of activities related to the provision of the service include:

- Ensure compliance to regulatory and shareholder requirements on total compensation and governance related issues

Total Compensation Department

The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The Total Compensation Department supports this service by providing human resources expertise, monitoring and ensuring compliance to regulatory and shareholder requirements.

Examples of activities related to the provision of the service include:

- Ensure compliance to regulatory and shareholder requirements on executive compensation and governance related issues

Enterprise Security Department

The Corporate Compliance service is responsible for developing the corporate governance structure and policies. The Enterprise Security Department supports this service by building, leading, motivating and maintaining the Corporate Security Steering Committee, a cross business unit team of Security professionals at Enbridge, responsible for the Enterprise Wide security and protection strategy and program development in compliance with US and Canadian government and industry standards and guidelines across the organization.

Examples of activities related to the provision of this service include:

- Support to EGD through the audit of EGD security vulnerability assessments for facilities in compliance with Canadian Standards' association standard Z246.1
- Investigation of allegations of non-compliance received through the Ethics and Conduct Anonymous Hotline at the request of the Chief Compliance officer

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$77,565
CFO	$16,626
People and Partners	$35,163
Corporate Controller	$18,331
Corporate HR	$6,540
Total Compensation	$42,977
Enterprise Security	$0
Total	**$197,202**

Expected Deliverables

- Develop and maintain corporate compliance guidelines, policies and standards designed to assist EGD management in its governance activities

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Quantity and Quality of Service	
	• Zero governance failures • Zero control failures • Timely policy changes to reflect changes in the regulatory environment and to safeguard assets
Authorized Signature	
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2, 2012 Date

9. Emerging Energy Technology Research

Service Description	
Service Definition:	The Emerging Energy Technology Research service provides a single point of contact for the research and evaluation of all new or emerging technologies.
Services Identified by Department	**Corporate Development and Planning Department** The Emerging Energy Technology Research service provides a single point of contact for the research and evaluation of all new or emerging technologies. The Corporate Development and Planning Department supports this service by providing a single point of contact for the evaluation and management of all new or emerging technologies. Examples of activities related to the provision of the service include: • Respond to requests from EGD to examine new or emerging technologies that complement EGD's long term strategic objectives • Assess the commercial viability of emerging operational technologies, including analysis of markets and customers • Acts as an internal R&D function to examine the development of new capabilities related to service delivery or operational performance • Coordinate resources from EGD for evaluation and analysis purposes • Develop presentations for EGD EMT and Board of Directors on all potential opportunities **Alternative and Emerging Technology Department** The Emerging Energy Technology Research service provides a single point of contact for the research and evaluation of all new or emerging technologies. The Alternative and Emerging Technology Department supports this service by providing a single point of contact for the evaluation and management of all new or emerging technologies. Examples of activities related to the provision of the service include: • Respond to requests from EGD to examine new or emerging technologies that complement EGD's long term strategic objectives • Assess the commercial viability of emerging operational technologies, including analysis of markets and customers • Acts as an internal R&D function to examine the development of new capabilities related to service delivery or operational performance • Coordinate resources from EGD for evaluation and analysis purposes • Evaluate new energy technologies and pursue opportunities in the areas of carbon capture sequestration and stationary fuel cells • Develop presentations for EMT and EGD Board of Directors on all potential opportunities • Fuel Cell lobbying efforts with Government of Ontario • Clean Energy stakeholder submissions into the OPA's program development for CHPSOP and ERSOP • Federal level support for taxes on Clean Energy Credits that would support EGD investments and EGD customer investments • Collaboration efforts on claims for Scientific Research and Experiments Development (SRED) tax credits • Secure Government Funding from Environment Canada – up to $500k offsetting EGD operational costs as part of the Federal Government's Asia Pacific Partnership Funding • Collaborate with EGD technical staff for technology optimization of the pressure let-down asset(s)

	• Enhance outreach and funding support for EGD participation in industry networks such as NYSEARCH, The Canadian Hydrogen and Fuel Cell Association, etc.
Service Recipient:	Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution
Cost of Service	
	(see table below)
Expected Deliverables	
	• Support EGD leadership by researching and identifying business opportunities related to emerging energy technologies • Support for Investing in appropriate emerging technologies • Reports & presentations on emerging technologies, specifically fuel cells
Quantity and Quality of Service	
	• On demand access to expertise and research • Research analyses, reports and presentations relevant to EGD
Authorized Signature	
	Mr. Arunas Pleckaitis Vice-President Business Development & Customer Strategy Enbridge Gas Distribution MAR 02/12 Date

Department	Service Charge
Corporate Development and Planning	$0
Alternative and Energy Technology	$0
Total	**$0**

10. Employee and Labour Relations

Service Description	
Service Definition:	The Employee and Labour Relations service provides the development of strategies (overall framework, vision and policies) and tactics for the management of unionized, JIC and potentially-unionized employees and supports the development of employee-related principles and policies.
Services Identified by Department	**<u>People and Partners Department</u>** The Employee and Labour Relations service provides the development strategies and tactics for the management of unionized, JIC and potentially-unionized employees and supports the development of employee-related principles and policies. The People and Partners Department supports this service by providing senior leadership and advice regarding EGD union employees. Examples of activities related to the provision of the service include: • Provides broad direction and oversight to employee and labour relations including providing EGD with a voice to the EI Board Human Resources Committee **<u>Labour Relations Department</u>** The Employee and Labour Relations service provides the development strategies and tactics for the management of organized employees (unionized, Joint Industrial Council and potentially-unionized employees) and supports the development of employee-related principles and policies. The Labour Relations Department supports this service by providing resources and operational support to the development and implementation of labour and labour relations strategies. Examples of activities related to the provision of this service include: • Providing advice and counsel to managers and supervisors, Services Recipient's HR Dept. with respect to all grievances and the arbitration process • Co-ordination of the grievance process with managers, union and employees • Coordinate legal resources to support Labour Board issues • Leading, coordinating and representing the Services Recipient during Arbitration process • Leads, researches and co-ordinates the response to Labour Board applications such as certifications, union labour practices and jurisdictional disputes. • Responding to all Policy grievances with respect to recognition and jurisdiction • Analyze grievance and arbitration trends as input to the collective bargaining process and/or education of line managers • Assisting in the development of a Unionized Performance Management Program • Liaise with HR to ensure consistency with non-unionized employee performance management program • Providing training to Managers on the implementation of a Unionized Performance Management Program • Participate and assist in the Health Center and Workers Safety and Insurance Board return to work programs that require Union concurrence • Support the "Healthwise" program for union employees including the coordination of the employees' entitlement to benefits • Facilitate the development and implementation of a collective bargaining

strategy, mandate and tactics

- Support development of the mandate by collecting and analyzing competitive information on other negotiated agreements and other information provided by compensation and benefits staff within HR
- Provide detailed trend and economic analysis with recommendations for mandate approval
- Provide detailed current costing and final cost reporting
- Develop communication materials and process to educate senior managers and HR consultants on terms of the new collective agreement, including the interpretation and administration of the agreement.
- Coordinate legal resources to support collective agreement issues
- Provide guidance to the Service Recipient with respect to the spirit and intent of the Collective Agreement
- Providing advice to the Services Recipient's HR and Line Managers regarding Collective Agreement interpretation
- Assess new positions to determine whether they are in or out of the Bargaining Unit based on current recognition clause
- Assist in the development of the job evaluation system
- Assist in the job evaluation committee's functions
- Contribute to the overall growth and development of corporate strategy directions through participation on senior management committee/teams with an emphasis on labour relations issues and implications with respect to operational plans and/or change initiatives
- Act as a Corporate resource in the development of employee relations principles and policies

Corporate Human Resources Department

The Employee and Labour Relations service provides the development strategies and tactics for the management of organized employees (unionized, Joint Industrial Council and potentially-unionized employees) and supports the development of employee-related principles and policies. The Corporate Human Resources Department supports this service by providing leadership and direction in managing organized employees and leadership in employee relations directly and indirectly through chairing the Human Resource Committee.

Examples of activities related to the provision of this service include:

- Provide policy direction and review for strategies and tactics for the management of organized employees and the development and oversight of EGD-specific and enterprise-wide employee relations strategies and employee-related policies.

Pension & Benefits Department

The Employee and Labour Relations service provides the development strategies and tactics for the management of organized employees (unionized, Joint Industrial Council and potentially-unionized employees) and supports the development of employee-related principles and policies. The Pension & Benefits Department supports this service by participating in union negotiations and contract administration activities and by providing the leadership both directly and indirectly through chairing the Human Resource Committee.

Examples of activities related to the provision of this service include:

- Provide specialized resources for developing and negotiating collective bargaining agreements with respect to pension and benefits
- Assist in annual development and communication of pension and benefit changes and implications for members
- Develop, coordinate and manage employee-related policy issues.

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Organizational Effectiveness Department

The Employee and Labour Relations service provides the development and strategies and tactics for the management of unionized employees (unionized, Joint Industrial Council and potentially-unionized employees) and supports the development of employee-related principles and policies. The Talent Management & Workforce Planning Department supports this service by identifying enterprise-wide and EGD-specific employee relations strategies and policies and (upon approval) developing same for implementation.

Examples of activities related to the provision of this service include:

- Work with EGD executive and leadership teams to develop enterprise-wide and EGD-specific employee relations strategies and HR policies

Service Recipient: Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
People and Partners	$13,543
Labour Relations	$428,522
Corporate HR	$36,136
Pension & Benefits	$0
Organizational Effectiveness	$0
Total	**$478,201**

Expected Deliverables

- Support EGD's leadership in the development of Labour Relations strategies and tactical plans
- Provide EGD management with policies, guidelines and resources designed to support the successful development and implementation of the Union/JIC Labour Plans and Employee Relations policies and plans

Quantity and Quality of Service

- Documented Strategies
- Implementable strategy (at a level of detail that allows EGD to execute)
- Successful Union relations - # grievances, arbitrations, Labour Board issues, cooperation/support for internal initiatives
- Successful employee relations – no issues regarding Humans Rights legislation, Privacy legislation etc.
- No Union labour disruptions
- Cost effective means to access senior level technical expertise as required

Authorized Signature

Mr. Marc Weil
Director Human Resources
Enbridge Gas Distribution

March 2, 2012
Date

11. Employee Development

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise.</td></tr>
<tr><td>Services Identified by Department</td><td><u>CEO Department</u>
The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise. The CEO Department supports this service by providing senior leadership to executive recruiting and succession planning activities.

Examples activities related to the provision of the service include:
Participate actively in the recruiting of all company officers for EGD
Participate in the executive succession planning activities
Review finalized recommendations and develop plans for approval by the EI Board of Directors
<u>People and Partners Department</u>
The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise. The People and Partners Department supports this service by managing executive succession planning for senior EGD positions.

Examples of activities related to the provision of the service include:
Coordinate the annual review process by Executive of their identified successors (either internally identified or externally required)
Initiate review process through formal identification of executive succession candidates
Coordinate assessment process of all executive succession candidates and positions
Compile assessments, finalize recommendations and present findings and recommendations of Directors for approval
Engage external consultants to conduct external recruitment if required
Coordinate internal transfers of key staff if required
Identify opportunities for EGD executives outside their own business unit
Enhance attraction and retention of executive - level employees
<u>Organizational Effectiveness Department</u>
The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise. The Organizational Effectiveness Department supports this service by developing and coordinating the implementation of workforce plans, employee learning strategies and resources, and talent management initiatives.

Examples of activities related to the provision of the service include:</td></tr>
</table>

- Research industry, market and internal demographics (workforce analytics) to identify available skill sets and resources
- Conduct competency gap analysis of internal requirements based on strategic plans
- Identify internal (promotions, transfers and succession planning across enterprise) and external (contractors and consultants) alternatives to fill gaps at the executive level
- Coordinate the execution and implementation of succession management across the enterprise to expand EGD's potential talent pool
- Identify and assess internal competency requirements and develop learning plan to address competency gaps
    - Collaborate enterprise-wide (including EGD) to identify common cross company training and development needs
    - Coordinate the development of learning frameworks and implementation plan to address identified needs including competency profiling
    - Manage the research and development of Enbridge-wide training programs, communication requirements and supporting tools, both internally and externally with service providers, department leaders and staff for the benefit of EGD
    - Develop employee feedback mechanisms (performance assessments and employee surveys), manage the feedback mechanism and distribute results

Corporate Human Resources Department

The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise, including EGD. The Corporate Human Resources Department supports this service by providing operational support and resources for workforce planning, succession management, recruiting skill development, leadership development and workforce management activities.

Examples of activities related to the provision of the service include:

- Develop administrative policies and processes for enterprise wide workforce strategy development, workforce planning modeling, succession planning and employee development
- Provide operational and systems support to succession management, performance management and employee development processes
- VP HR provides oversight and senior level expertise in the determination and development of talent management strategies, policies and initiatives

HR Enterprise Business Solutions Department

The Employee Development service provides long-range planning and the development and support of employee development and talent management programs to support business strategies and ensure the supply and development of employees across the enterprise. The HR Enterprise Business Solutions Department supports this service by providing facilitation, business requirements and functional support for workforce planning, succession management, recruiting skill development, leadership development and workforce management activities.

Examples of activities related to the provision of the service include:

- Facilitate Corporate HR in the development of business processes for workforce strategy development, workforce planning modeling, succession planning and employee development
- Provide systems and functional support to succession management,

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	performance management and employee development processes
Service Recipient:	Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$503,231
People and Partners	$41,921
Organizational Effectiveness	$669,944
Corporate HR	$15,017
HR Enterprise Business Solutions	$30,455
Total	**$1,260,568**

Expected Deliverables

- Support EGD in the continuous development of competitive and innovative personnel strategies that balance EGD's employee retention and personal development goals with fiscal responsibility and the interests of shareholders
- Provide EGD management with policies, guidelines and resources designed to support the successful development and implementation of the Employee Development strategy
- Enterprise-wide Employee and Leadership Development learning programs

Quay and Quality of Service

- High Employee Engagement and Motivation as measured through the internal employee survey
- High Staff Retention rate
- Detailed workforce plans and skills assessments

Authorized Signature

Mr. Marc Weil
Director Human Resources
Enbridge Gas Distribution

March 2, 2012
Date

12. Enterprise IT Program Management

Service Description	
Service Definition:	The Enterprise IT Program Management service is responsible for the overall coordination, and monitoring of major enterprise projects.
Services Identified by Department	**IT Planning and Governance Department** The Enterprise IT Program Management service is responsible for the overall coordination and monitoring of major enterprise projects. The IT Planning and Governance Department supports this service by assuming project management responsibilities for major enterprise projects, including their successful implementation on-time and on-budget. Examples of activities related to the provision of the service include: • Development of program / project management policies and procedures for implementing and managing enterprise wide systems • The development of complex project plans, charters, budgets and other required project documentation • Research new alternatives to conducting business through different service approaches (i.e. IT outsourcing) • Coordination of project teams including requisition of the appropriate IT skills when required • Monitoring ongoing projects to maintain alignment with strategic and project objectives; including the provision of progress reports to senior management • Run post-project reviews on corporate projects to assess and learn from the process • Provide financial reporting on corporate project performance to help EGD understand the financial specifics for all enterprise projects. • Implement change management requirements of IT projects. All enterprise IT projects must follow a rigorous process that includes strict adherence to change management processes. **CIO Department** The Enterprise IT Program Management service is responsible for the overall coordination and monitoring of major enterprise projects. The CIO Department supports this service by assuming project management responsibilities for major enterprise projects, including their successful implementation on-time and on-budget. Examples of activities related to the provision of the service include: • The development of project plans, charters, budgets and other required project documentation • Coordination of project teams including requisition of the appropriate IT skills when required • Monitoring ongoing projects to maintain alignment with strategic and project objectives; including the provision of progress reports to senior management • Develop training material and provide training to users of enterprise systems. Appropriate training ensures users are prepared to use the systems • Run post-project reviews on corporate projects to assess and learn from the process • Provide financial reporting on corporate project performance to help EGD

	understand the financial specifics for all enterprise projects. • Implement change management requirements of IT projects. All enterprise IT projects must follow a rigorous process that includes strict adherence to change management processes.
Service Recipient:	Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
IT Planning and Governance	$465,106
CIO	$403,388
Total	**$868,494**

Expected Deliverables

- Provide strategic planning and management guidance in the identification and design of Enterprise IT systems for the benefit of EGD
- Align technology strategy to EGD's long term strategic needs
- Ensure technologies meet business needs and are scalable and serviceable as required
- Ensuring security and maintenance of the integrity of the data and information content.
- Ensuring availability of an intranet portal that is structured effectively for EGD needs.
- Provide an IT Strategic Plan that is aligned with the goals and objectives of EGD. This includes all areas of IT service delivery.
- Provide corporate IT policies to govern the administration and operation of EGD's systems and enterprise systems EGD uses.
- Provide senior executive information technology expertise which is not resident within EGD.
- Provide opportunities to share experiences, programs and initiatives with other internal IT organizations in order to take advantage of alternate delivery methodologies, technical architectures, IT processes, and apply the learnings to EGD's benefit.
- For enterprise systems EGD utilizes (EFS, HRIS, Sharepoint, Livelink) providing a formal enterprise architecture plan. This includes the development and ongoing maintenance of the architecture plan.
- For enterprise systems EGD utilizes (EFS, HRIS, Sharepoint, Livelink)) providing systems that meet performance and functionality objectives on an ongoing basis.
- For those enterprise projects that benefit EGD, provide Project Management support needed to launch the projects. This would include project budgeting, and the initial solution architecture.
- Provide corporate IT policies to govern the security of EGD's systems and enterprise systems EGD uses.

Quantity and Quality of Service

- Effective, reliable and low IT infrastructure
- Ensure vendor relationships are managed effectively.
- Ensuring compliance with all relevant legislation affecting information systems.
- Ensuring that all supply chain initiatives conform to industry standards and best practices.
- Ensuring that all of the contracts are effectively negotiated and managed.

Authorized Signature

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

RB	Mr. Henry Wong Director Information Technology Enbridge Gas Distribution	Mar. 7, 2012 Date

13. Enterprise IT Strategy Planning & Management

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Enterprise IT Strategy Planning and Management service governs the development of enterprise wide strategies, policies and standards for information technologies.</td></tr>
<tr><td>Services Identified by Department</td><td><u>People and Partners Department</u>
The Enterprise IT Strategy Planning and Management service governs the development of enterprise wide strategies, policies and standards for information technologies. The People and Partners Department supports this service by providing senior leadership and advice regarding the corporate information technology strategy and its alignment to the EGD long range plan.

Examples of activities related to the provision of the service include:
• Responsible for the review and approval of information technology project concepts and IT project expenditure
• Responsible for IT security and the interfaces around enterprise-wide applications, for example, EFS, HRIS and the intranet portal
• Responsible for structure and usage of intranet portal related to human resource issues and internal communication issues

<u>CIO Department</u>
The Enterprise IT Strategy Planning and Management service governs the development of enterprise wide strategies, policies and standards for information technologies. The CIO Department supports this service by providing leadership and IT expertise. The CIO Department is also responsible for developing and implementing the IT strategy in support of the EGD long range plan.

Examples of activities related to the provision of the service include:
• Manage the development and alignment of the enterprise IT Strategic plan to the long range plan, with consideration of the following areas
    o Knowledge management
    o Document management
    o Information management
    o Network infrastructure
    o Information technology architecture
    o Application suite
    o Support and maintenance provisions
• Manage the compliance of the IT strategic plan; ensure services are delivered in a manner consistent with the goals and objectives of EGD.
• Set, administer, and manage compliance of IT policies and procedures for enterprise (posted on elink).
• Manage and administer all of the enterprise-wide IT vendor and outsourcing relationships (e.g. Peoplesoft HR, Sharepoint Portal, and Livelink Records Management)
• Manage the enterprise IT architecture including ongoing monitoring of new architecture requirements and issues; includes planned annual review of enterprise architecture
• Research and analyze current trends, alternative delivery models, outsourcing and other related IT matters. Monitor current trends in the IT industry and apply those learnings at EGD.
• Manage the enterprise IT system performance through customers feedback surveys, stakeholder workshops and internal/external IT audits
• Identify opportunities for improved business support
• Provide EGD with senior executive level information technology guidance</td></tr>
</table>

to assist with improving how EGD IT supports the business.

- Coordinate and conduct the approval process for enterprise wide services, including execution of scoping, concept generation, and budgeting required to gain final approval
- Monitors and maintains compliance with regulatory requirements (e.g. privacy legislation and how it applies to voice over internet protocol (VOIP), security, password protection and employee/employer rights)
- Contributes to annual performance review of EGD IT Director and managers
- Provides leadership on dealing with security issues
    - Develop, update and deploy IT policies, methods, technology standards best practices, and tools to meet EGD security requirements
    - Monitor and manage security of data, applications, network, and computing platforms
    - Research and analyze new security technologies
    - Coordinate and manage implementation of new security technologies
    - Conduct annual IT Security Audit using ISO framework; Periodic coordination of external IT security audits
- Conduct RFP, vendor/system analysis, and ultimate selection of vendors for enterprise-wide systems that EGD uses (EFS, HRIS, Sharepoint, Livelink)
- Coordinate and participate in negotiation of new contracts and contract renewals for those enterprise systems that EGD uses (EFS, HRIS, Sharepoint, Livelink)
- Manage overall vendor relationship for those enterprise systems that EGD uses (EFS, HRIS, Sharepoint, Livelink) to ensure that appropriate management attention is paid to maintaining the vendor relationship so that maximum value can be attained for EGD.
    - Act as escalation point for all unresolved IT vendor issues.
    - Handle administration and payment approval of maintenance contracts and additional license fees for EGD applications

IT Planning and Governance Department

The Enterprise IT Strategy Planning and Management service governs the development of enterprise wide strategies, policies and standards for information technologies. The IT Planning and Governance Department supports this service by providing leadership and IT expertise. The IT Planning and Governance Department is also responsible for developing and implementing the IT strategy in support of the EGD long-range plans.

Examples of activities related to the provision of the service include:

- Develop and align the enterprise IT Strategic plan to the long range plan, with consideration of the following areas
    - Knowledge management
    - Document management
    - Information management
    - Network infrastructure
    - Information technology architecture
    - Application suite
    - Support and maintenance provisions
- Providing senior IT executive advice and counsel to EGD on the acquisition and implementation of new software products.
- Monitor compliance of the IT strategic plan, ensuring services are delivered in a manner consistent with the goals and objectives of EGD.
- Set, administer, and manage compliance of IT policies and procedures for

EGD.

- Manage and administer all of the enterprise-wide IT vendor and outsourcing relationships (e.g. PeopleSoft HR, Employee Portal, and Livelink Records Management)
- Define the EGD IT architecture including ongoing monitoring of new architecture requirements and issues; includes planned annual review of IT Planning and Governance
- Research and analyze current trends, alternative delivery models, outsourcing and other related IT matters. Monitor current trends in the IT industry and apply those learnings at EGD.
- Monitor EGD IT system performance through customers feedback surveys, stakeholder workshops and internal/external IT audits
- Identify opportunities for improved business support
- Provide EGD with senior executive level information technology guidance to assist with improving how IT supports the business.
- Coordinate and conduct the approval process for EGD services, including execution of scoping, concept generation, and budgeting required to gain final approval
- Monitors and maintains compliance with regulatory requirements (e.g. privacy legislation and how it applies to voice over internet protocol (VOIP), security, password protection and employee/employer rights)
- Contributes to annual performance review of EGD IT managers
- Provides leadership on dealing with security issues
    - Develop, update and deploy IT policies, methods, technology standards best practices, and tools to meet EGD security requirements
    - Monitor and manage security of data, applications, network, and computing platforms
    - Research and analyze new security technologies
    - Coordinate and manage implementation of new security technologies
    - Conduct annual IT Security Audit using ISO framework; Periodic coordination of external IT security audits
- Conduct RFP, vendor/system analysis, and ultimate selection of vendors for EGD systems
- Coordinate and participate in negotiation of new contracts and contract renewals
- Manage overall vendor relationship for enterprise systems
- Act as escalation point for all unresolved IT vendor issues
- Handle administration and payment approval of maintenance contracts and additional license fees for corporate applications

Service Recipient: Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
People and Partners	$181,220
CIO	$0
IT Planning and Governance	$442,895
Total	**$624,115**

Expected Deliverables

- Provide strategic planning and management guidance in the identification and design of Enterprise IT systems for the benefit of EGD
- Align technology strategy to EGD's long term strategic needs
- Ensure technologies meet business needs and are scalable and

	serviceable as required • Ensuring security and maintenance of the integrity of the data and information content. • Ensuring availability of an intranet portal that is structured effectively for EGD needs. • Provide an IT Strategic Plan that is aligned with the goals and objectives of EGD. This includes all areas of IT service delivery. • Provide corporate IT policies to govern the administration and operation of EGD's systems and enterprise systems EGD uses. • Provide senior executive information technology expertise which is not resident within EGD. • Provide opportunities to share experiences, programs and initiatives with other internal IT organizations in order to take advantage of alternate delivery methodologies, technical architectures, IT processes, and apply the learnings to EGD's benefit. • For enterprise systems EGD utilizes (EFS, HRIS, Sharepoint, Livelink) providing a formal enterprise architecture plan. This includes the development and ongoing maintenance of the architecture plan. • For enterprise systems EGD utilizes (EFS, HRIS, Sharepoint, Livelink)) providing systems that meet performance and functionality objectives on an ongoing basis. • For those enterprise projects that benefit EGD, provide Project Management support needed to launch the projects. This would include project budgeting, and the initial solution architecture. • Provide corporate IT policies to govern the security of EGD's systems and enterprise systems EGD uses.
Quantity and Quality of Service	
	• Effective, reliable and low IT infrastructure • Ensure vendor relationships are managed effectively. • Ensuring compliance with all relevant legislation affecting information systems. • Ensuring that all supply chain initiatives conform to industry standards and best practices. • Ensuring that all of the contracts are effectively negotiated and managed.
Authorized Signature	
RB	[signature] Mr. Henry Wong Director Information Technology Enbridge Gas Distribution Mar. 7, 2012 Date

14. Expense System Management & Technical Support (Oracle iExpense)

Service Description	
Service Definition:	The Expense System Management and Technical Support (Oracle iExpense) service is responsible for the technical support and administration of the automated purchasing and employee expense reporting tool (Oracle iExpense). Oracle iExpense is an online system, used in reporting employee expenses, where all expenses incurred via Amex or BMO corporate cards are uploaded automatically. Oracle iExpense contains an approval hierarchy where all expense report approvals are done electronically. EGD requires this service to ensure efficient and accurate processing of automated purchasing and employee expenses

Services Identified by Department	**<u>CIO Department</u>**
	The Expense System Management and Technical Support (Oracle iExpense) service is responsible for the technical support and administration of the automated purchasing and employee expense reporting tool (Oracle iExpense). The CIO Department supports this service by providing leadership and management to IT resources providing services: IT System Analysts, IT DBA resources, IT Infrastructure resources, and IT contract resources. Responsible for overseeing all IT related activities from day-to-day technical support to strategic planning for Enterprise Financial Systems (Oracle iExpense).
	
	Examples of activities related to the provision of this service include:
	• Ensure the Oracle iExpense application is effectively managed
	• Assist senior business leadership in terms of IT process changes, business process changes, incremental infrastructure, data, and support processes through interaction with the EFS Governance Committee, representing executive finance and IT management from across Enbridge.
	• Establish and maintain effective communication and relationship with systems' vendors to ensure prompt and cost efficient vendors support.
	• Develop, coach and mentor EFS Strategy and Services employees and contractors
	• Drive the implementation and compliance to quality assurance procedures, standards for process design, documentation, configuration changes, functionality enhancements, and a release management strategy to protect the integrity and reliability of financial data.
	• Proactively gather and make recommendations regarding complex intelligence from across Enbridge and externally to assess immediate and future impacts on EFS applications, processes, and priorities.
	• Establish and maintain an effective external network with appropriate application user groups, industry groups, and business partners to share knowledge, gain intelligence, learn cost avoidance strategies, understand alternatives and trends to anticipate, plan, and ensure continuing operational excellence in the support of EGD's evolving business needs.
	• Vendor Management
	    o Negotiate, monitor and manage expense management system vendor contract
	    o Negotiate, monitor and manage IT outsourcing relationships with respect to the expense manage system
	    o Research and monitor emerging technologies
	
	<u>EFS Strategy and Services Department</u>

The Expense System Management and Technical Support (Oracle iExpense) service is responsible for the technical support and administration of the automated purchasing and employee expense-reporting tool (Oracle iExpense). The EFS Strategy and Services Department supports this service by providing technical expertise to the operation of the expense system.

Examples of activities related to the provision of this service include:

- Manage client relationships and communication
- Lead the strategic planning process in relation to efficiency and effectiveness of EFS applications
- Reporting & Analysis
    - Provide reporting to management for tracking expenses and supply purchases to ensure policy compliance, spend volume and strategic sourcing performance objectives
    - Provision of standard reports
    - Ad hoc report generation
    - Augment, add, or remove reporting requirements
- Technical Support
    - Interface management
    - System configurations, customization or enhancements
    - Release management
    - Master-file maintenance
    - Manage development life cycle
    - Monitor system performance
- Vendor Management
    - Negotiate, monitor and manage expense management system vendor contract
    - Negotiate, monitor and manage IT outsourcing relationships with respect to the expense manage system
    - Research and monitor emerging technologies

<u>Corporate Administration Department</u>

The Expense System Management and Technical Support (Oracle iExpense) service is responsible for the technical support and administration of the automated purchasing and employee expense-reporting tool (Oracle iExpense). The Corporate Administration Department supports this service by providing end user administrative support and maintenance services with respect to the two credit card programs.

Examples of activities related to the provision of this service include

- User support activities
    - Management and user support of Oracle iExpense system (does not include system support)
    - Provide back up system support
    - Manage employee business and travel expense policy and purchasing card agreements
    - Provide strategic, operational and compliance reporting to management for expense tracking and other objectives
- Maintenance services
    - Manage and maintain cardholder database
    - Facilitate cardholder / vendor issues
    - Monitor and follow-up overdue balances

Service Recipient:	Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge

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CIO	$35,587
EFS Strategy and Services	$30,650
Corporate Admin.	$29,253
Total	**$95,490**

Expected Deliverables

- Ensure availability of the infrastructure and Expense System (Oracle iExpense) to support personnel in their claim submission and recovery activities
- Provide user support as required
- Provide an expense management system to ensure adequate tracking, control, and payment of employee expenses.
- Ensuring technical support and management of the Oracle iExpense system to ensure the effective ongoing operation of the system.
- Ensuring alignment with the goals and objectives of EGD which is driven by a relevant governance structure.

Quantity and Quality of Service

- Continuous and uninterrupted access
- Accuracy and integrity of claims and payments.
- On demand user support
- Effective and efficient support for Oracle iExpense.
- Ensuring an effective relationship with the Oracle iExpense vendor
- Ensuring availability of staff that possesses the competencies required to fulfill their job responsibilities.
- Ensuring compliance with all relevant best practices (e.g. ITIL, COSO) to maintain system integrity and reliability.
- Ensuring a diligent process of request prioritization, including assessing cost, resources, systems impacts, and business value to determine which requests will go forward.
- Ensuring EGD is up to date with application market developments external to Enbridge. This includes networking with relevant peer companies to gain knowledge and apply to EGD where appropriate
- Ensuring a relationship with the vendor who supports Oracle iExpense.

Authorized Signature

Rb

Mr. Henry Wong
Director Information Technology
Enbridge Gas Distribution

Mar. 7, 2012
Date

15. External Audit Coordination

Service Description

Service Definition: The External Audit Coordination service is responsible for coordinating and managing the external auditors and their related supporting activities.

Services Identified by Department

CFO Department

The External Audit Coordination service is responsible for coordinating and managing the external auditors and their related supporting activities. The CFO Department supports this service by providing senior leadership and overall management guidance.

Examples of activities related to the provision of the service include:

- Support negotiation of audit fees

Audit Services Department

The External Audit Coordination service is responsible for coordinating and managing the external auditors and their related supporting activities. The Audit Services Department supports this service by assuming responsibility for coordinating internal resources and managing external auditors.

Examples of activities related to the provision of the service include:

- Coordinate internal resources in the development of the audit plan with external auditors
- Participate in the negotiation of external auditor fees and certification outsourcing (PWC, Accenture Business Services) fees on behalf of EGD
- Assist in coordinating the external audit in conjunction with EGD to minimize duplication and enhance audit efficiencies
- Provide advice on specific audit issues and procedures
- Coordinate communications to external auditors
- Assess changes in business practices and their impact on the audit plan

Corporate Controller Department

The External Audit Coordination service is responsible for coordinating and managing the external auditors and their related supporting activities. The Corporate Controller Department supports this service by assuming responsibility for coordinating and managing external auditors.

Examples of activities related to the provision of the service include:

- Coordinate audit plan development with external auditors
- Negotiate external auditor fees and certification outsourcing (PWC, Accenture Business Services) fees on behalf of EGD
- Coordinate the external audit in conjunction with EGD to minimize duplication and enhance audit efficiencies

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CFO	$84,158
Audit Services (Calgary)	$0
Corporate Controller	$19,241
Total	**$103,399**

Expected Deliverables

	• Efficient, well managed and timely audit turnarounds
Quantity and Quality of Service	
	• Competitive audit fees (pricing of audits that benefit from economies of scale) • On demand access to financial, accounting and auditing expertise
Authorized Signature	
	Nkishinchandani Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2, 2012 Date

16. Financial and Project Accounting System Technical Support (Oracle)

Service Description	
Service Definition:	The Financial and Project Accounting System Technical Support (Oracle) service provides the system support and maintenance, system customization and enhancements for the Enbridge Financial and Project Accounting Management system (Oracle). The Enbridge Financial and Project Accounting Management system (Oracle) includes General Ledger, Accounts Payable, Purchasing, (including i-Procurement), Order Management, Accounts Receivable, Cash Management, Fixed Asset, Projects, Plant Accounting and Inventory modules.

Services Identified by Department	**<u>CIO Department</u>**
	The Financial and Project Accounting System Technical Support (Oracle) service provides the system support and maintenance, system customization and enhancements for the Enbridge Financial and Project Accounting Management system (Oracle). The CIO Department supports this service by providing leadership and management to IT resources providing services: IT System Analysts, IT DBA resources, IT Infrastructure resources, and IT contract resources. Responsible for overseeing all IT related activities from day-to-day technical support to strategic planning for Enterprise Financial Systems (Oracle Financials).
	
	Examples of activities related to the provision of this service include:
	• Coordinate collaboration and integration across Enbridge IT departments to ensure IT activities support enterprise requirements and to ensure Oracle Financials application is effectively managed
	• Assist senior business leadership in terms of IT process changes, business process changes, incremental infrastructure, data, and support processes
	• Establish and maintain effective communication and relationship with systems' vendors to ensure prompt and cost efficient vendors support.
	• Develop, coach and mentor EFS Strategy and Services employees and contractors
	• Drive the implementation and compliance to quality assurance procedures, standards for process design, documentation, configuration changes, functionality enhancements, and a release management strategy to protect the integrity and reliability of financial data.
	• Proactively gather and make recommendations regarding complex intelligence from across Enbridge and externally to assess immediate and future impacts on EFS applications, processes, and priorities.
	• Establish and maintain an effective external network with appropriate application user groups, industry groups, and business partners to share knowledge, gain intelligence, learn cost avoidance strategies, understand alternatives and trends to anticipate, plan, and ensure continuing operational excellence in the support of EGD's evolving business needs.
	• Vendor Management
	    o Negotiate, monitor and manage vendor contract
	    o Negotiate, monitor and manage IT outsourcing relationships
	    o Research and monitor emerging technologies
	    o IT Planning and Governance
	
	<u>EFS Strategy and Services Department</u>
	The Financial and Project Accounting System Technical Support (Oracle) service provides the system support and maintenance, system customization and enhancements for the Enbridge Financial and Project Accounting Management

system (Oracle). The EFS Strategy and Services Department supports this service by providing technical expertise and assuming responsibility for providing the required system support and maintenance, system customization and enhancements for the Enbridge Financial and Project Accounting Management system (Oracle).

Examples of activities related to the provision of this service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of EFS applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User (incl. super user / power user) training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Master-file maintenance
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

Service Recipient: Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$192,580
EFS Strategy and Services	$159,581
Total	**$352,161**

Expected Deliverables

- Ensure availability of the financial and other information contained within Oracle System (This system maintains the general ledger and actual transactional data which supports all EGD's requirements for financial reporting and decision making.
- Provide user support as required
- Provide infrastructure, policies and processes for recording financial results
- Ensure availability of a Financial and Project Accounting system to manage the financials for EGD.
- Ensure availability of technical support and management of the Oracle system to ensure the effective ongoing operation of the system.
- Ensuring an Oracle system that is aligned with the goals and objectives of EGD and which is driven by a relevant governance structure
- Ensuring a diligent process of request prioritization, including assessing cost, resources, systems impacts, and business value to determine which requests will go forward.

Quantity and Quality of Service

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	• Continuous and uninterrupted access to financial and other Management information • Accuracy and integrity of data. • On demand user support • Providing an effective relationship with Oracle to ensure timely and effective support from the vendor to business or technical issues. • Ensuring availability of technical staff that possesses the competencies required to fulfill their job responsibilities. • Ensuring compliance with all relevant best practices (e.g. ITIL, COSO) to maintain system integrity and reliability • Ensuring a diligent process of request prioritization, including assessing cost, resources, systems impacts, and business value to determine which requests will go forward. • Ensuring EGD is up to date with application market developments external to Enbridge. This includes networking with relevant peer companies to gain knowledge and apply to EGD where appropriate • Ensuring EGD maintains a relationship with the vendor who supports Oracle Financials.
Authorized Signature	
RB	Mr. Henry Wong Director Information Technology Enbridge Gas Distribution Mar. 7, 2012 Date

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

17. Gas Supply, Storage, and Transportation Strategy

Service Description

Service Definition:	The Gas Supply, Storage and Transportation Strategy service is responsible for supporting the development of the long-term (>5 year) gas supply, storage and transportation strategies. This includes providing forward looking projections on the potential cost of the gas supply, the location of the supply and related industry requirements for storage and transportation.
Services Identified by Department	**CEO Department** The Gas Supply, Storage and Transportation Strategy service is responsible for supporting the development of the long-term (>5 year) gas supply, storage and transportation strategies. This includes providing forward looking projections on the potential cost of the gas supply, the location of the supply and related industry requirements for storage and transportation. The CEO Department provides support to this service by providing leadership support and ensuring alignment to the long-range plan. Examples of activities related to the provision of the service include: • Participate and provide leadership in the development of strategies for alternative gas supply, storage and transportation • Monitor gas supply, storage and transportation activities to ensure alignment to long range plan
Service Recipient:	Mr. Jim Grant, Vice-President, Energy Supply, Storage Development & Regulatory Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$0
Total	**$0**

Expected Deliverables

- Support EGD's leadership by identifying issues related to gas supply, storage and transportation and developing a corresponding strategy(s)
- Provide EGD's management with guidelines and resources designed to support the successful development and implementation of a Gas Supply, Storage and Transportation strategy

Quantity and Quality of Service

- Forward looking Industry information related to gas supply, transportation and storage
- Timely access to knowledgeable resources
- Executable recommendations for inclusion in Enbridge Gas Distribution's strategy (at a level of detail that allows EGD to execute)

Authorized Signature

Mr. Jim Grant
Vice-President, Energy Supply,
Storage Development & Regulatory
Enbridge Gas Distribution

Feb. 29, 2012
Date

18. Government Relations

Service Description	
Service Definition:	The Government Relations service ensures EGD's interests are heard by government (federal, Ontario and municipal) officials, departments and committees.
Services Identified by Department	**Public and Government Affairs Department** The Government Relations service ensures EGD's interests are heard by government (federal, Ontario and municipal) officials, departments and committees. The Public and Government Affairs Department supports this service by meeting with government officials and committees and coordinating the use of external expertise. Examples of activities related to the provision of the service include: • Manage federal government liaison and public policy initiatives (specifically climate change/emissions management issues). • Manage government relations consultants in Ottawa. • Maintain relationship with key federal government contacts to keep communications channels open. • Manage and maintain EGD's federal government relations related to climate change and environmental initiatives through contact with government committees, industry associations and the environmental community. • Manage and maintain EGD's involvement with climate change and environmental initiatives through participation in the Corporate Climate Task Force • Analyze climate change issues and identifying risks and opportunities (e.g. regulatory obligations, access to capital, stakeholder relations, and domestic and international credibility) for EGD • Assist EGD in assessing its 'Triple Bottom Line'-based Greenhouse Gases emission projections done on an annual basis. Assist EGD in monitoring and tracking emissions and completing necessary governmental filing for NPRI, LFE frameworks, GHG Registry, etc.) • Monitor climate change obligations • Maintain contact with industry associations, government committees (across all levels of Government) and the environmental community • Ensures EGD provides relevant input into the Corporate Social Responsibility Report (CSR)
Service Recipient:	Ms. Debbie Boukydis, Director, Public & Government Affairs, Enbridge Gas Distribution Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Public & Government Affairs	$44,917
Total	**$44,917**

Expected Deliverables

- Ensure that EGD's interests are represented to Federal Government Officials and staff

Quality and Quantity of Service

- # of Government contacts relevant to EGD
- Positive relationships with key government entities

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	• Documented strategies • Comprehensive policies meeting EGD's needs • Investors and customers view EGD as a corporate environmental leader • EGD is well recognized by reporting agencies as having a "best in class" reporting classification • Plan clearly documents EGD's GHG emission levels, sources of emissions, emission reduction objectives and timelines
Authorized Signature	
	Debbie Boukydis Ms. Debbie Boukydis Director, Public & Government Affairs, Enbridge Gas Distribution March 26, 2012 Date

19. HRIS Program Management and Development

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams.

Specific HRIS application include the following PeopleSoft Modules:
Human Resources, Payroll for North America, Benefits Administration, Extended Enterprise, eCompensation, ePay, eBenefits, eProfile, eRecruit, eDevelopment, Time and Labour, eCompensation Manager Desktop, eProfile Manager Desktop, Directory Interface, ePerformance, HRMS Warehouse, PeopleSoft Portal.

Other HE technology applications include eLMS and workforce planning technologies.

And Supporting Infrastructure:
Sun, UNIX, Oracle, Web servers, development environments</td></tr>
<tr><td></td><td><u>CIO Department</u>
The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The CIO Department supports this service by providing strategic guidance to the technical support teams.

Examples of activities related to the provision of the service include:
• Vendor management,
• System management services,
• Project management services,
• Security and IT risk assessment services,
• Technical architecture planning services.

<u>Corporate Human Resources Department</u>
The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The Corporate Human Resources Department supports this service by providing HR user expertise and developing the required HR processes and controls.

Examples of activities related to the provision of the service include:
• Work with EGD to determine immediate and long-term HRIS and other HR technology requirements.
• Keep appraised of HRIS service offerings in the HRIS marketplace in North America.
• Keep appraised of PeopleSoft offerings.
• Work with EGD to match requirements and available services.
• Provide expertise required to support the development of business cases for the modifying, expanding or acquiring of new HRIS and other HR technology functionality.
• Work with IT HRIS development and business unit human resource staff to plan, execute and implement modifications, expansions or new HRIS and other HR technology functionality.</td></tr>
</table>

- Work with EGD human resource staff to train users.
- Work with EGD human resource staff to ensure maximum benefit is realized from HRIS investments.
- Conduct research on additional HRIS modules and other related matters for the purpose of improving support of business operational and strategic objectives
- Develop business case, project charter, project plan and other required project documentation; including securing project approval
- Organize and coordinate non-IT team resources (both internal and external resources)
- Develop business process and non-IT related training materials and provide training to EGD
- Advise on change management issues and communication plans
- Provide resources to other enterprise projects
- Reporting & Analysis
    - Provision of standard reports
    - Ad hoc report generation
    - Augment, add, or remove reporting requirements

HRIS Department

The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The HRIS Department supports this service by assuming technical responsibility for the required user training and support, system maintenance, system customization and enhancements.

Examples of activities related to the provision of the service include:

- Conduct research on additional HRIS modules and other related matters for the purpose of improving support of business operational and strategic objectives
- Work with stakeholders to identify required enhancements or changes to existing systems.
- Develop business case, project charter, project plan and other required project documentation; including securing project approval
- Organize and coordinate team resources (both internal and external resources)
- Manage the vendor selection and RFP process including the negotiation of all fees
- Manage and monitor project performance through to completion
- Reporting & Analysis
    - Provision of standard reports
    - Ad hoc report generation
    - Augment, add, or remove reporting requirements
- Technical Support
    - Interface management
    - System configurations, customization or enhancements
    - Release management
    - Master-file maintenance
    - Manage development life cycle
    - Monitor system performance
- Vendor Management
    - Negotiate, monitor and manage expense management system vendor contract
    - Negotiate, monitor and manage IT outsourcing relationships with

respect to the expense management system
- Research and monitor emerging technologies

Pension & Benefits Department

The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The Pension & Benefits Department supports this service by providing HR expertise and project management support.

Examples of activities related to the provision of the service include:

- Provide project management and definition support for pension and benefit related changes to HRIS system; including,
  - Develop business case, project charter, project plan and other required project documentation; including securing project approval (i.e. Time and Labour Project)
  - Organize and coordinate team resources (both internal and external resources)
  - Advise on change management issues and communication plans

HR Enterprise Business Solutions Department

The HRIS Program Management and Development service provides consulting services for support of the development and management of on-going HRIS and other HR technology system projects, including design, development, implementation, and coordination of project teams. The HR Enterprise Business Solutions Department supports this service by conducting initial business requirements gathering, functional design, data reporting, technical education and post go-live support, providing HR user the functional expertise to developing the required HR processes and controls.

Examples of activities related to the provision of the service include:

- Work with EGD to determine immediate and long-term HRIS requirements, and how it ties back to the HR Strategy
- Keep appraised of HRIS service offerings in the HRIS marketplace in North America (including PeopleSoft)
- Work with EGD to match business requirements and available services.
- Provide expertise required to support the development of business cases for the modifying, expanding or acquiring of new HRIS functionality.
- Work with IT HRIS development and business unit human resource staff to plan, execute and implement modifications, expansions or new HRIS functionality.
- Design training materials and work with EGD human resource staff to train users.
- Work with EGD human resource staff to ensure maximum benefit is realized from HRIS investments.
- Conduct research on additional HRIS modules and other related matters for the purpose of improving support of business operational and strategic objectives
- Work with stakeholders to identify required enhancements or changes to existing systems.
- Develop testing plans for any new addition to technology
- Maintain set-up tables to ensure that data is stored appropriately to deliver data to make decisions
- Provide resources to other enterprise projects
- Support & Maintenance

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

- Functional trouble shooting
- User support
- Provide user (incl. super user / power user) training materials & communication
- Change management
- Ad-hoc and on-going reporting requests
- Business requirements gathering for new functionality and enhancements to existing technology

Service Recipient: Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$465,956
Corporate HR	$150,591
HRIS	$1,622,414
Pension & Benefits	$0
HR Enterprise Business Solutions	$770,312
Total	**$3,009,273**

Expected Deliverables

- Ensure access to personnel records for all EGD staff as established by company policy
- Provide user support and the development of all HR-related technology applications
- Monitor and maintain the accuracy, integrity and confidentiality of the data contained within the HRIS and other HR technology systems
- Enhancements to the technological supports to maximize efficiencies of HR processes and leverage current and future functionality

Quality and Quantity of Service

- Continuous and uninterrupted access to HRIS system
- Accuracy and integrity of data
- On demand user support
- Efficient/Maximized usage of PeopleSoft system capability
- Expanded functionality achieved cost-effectively due to economies of scale

Authorized Signature

Mr. Marc Weil
Director Human Resources
Enbridge Gas Distribution

March 2, 2012
Date

20. Human Resource Advice

Service Description	
Service Definition:	The Human Resource Advice service provides research, expertise and support to internal initiatives. This includes support related to policy and systems development, personnel management, and adherence to regulatory and legislative requirements.

Services Identified by Department	**<u>CEO Department</u>**
	The Human Resource Advice service provides research, expertise and support to internal initiatives. This includes support related to policy and systems development, personnel management, and adherence to regulatory and legislative requirements. The CEO Department supports this service by assuming ultimate responsibility for policy development on Human Resources issues.
	
	Examples of activities related to the provision of the service:
	• Provides ultimate responsibility for all personnel policy issues and adherence to regulatory and legislative requirements
	• Provides ultimate responsibility for governance of the organization with respect to ensuring the proper procedures, policies, processes, people and culture to be successful
	
	<u>Corporate Human Resources Department</u>
	The Human Resource Advice service provides research, expertise and support to internal initiatives. This includes support related to policy and systems development, personnel management, and adherence to regulatory and legislative requirements. The Corporate Human Resource Department supports this service by developing and managing Human Resource systems and processes and providing leadership and expertise on Human Resource issues.
	
	Examples of activities related to the provision of the service:
	• Leader of the corporate Human Resources Leadership Team (HRLT) responsible for
	    o Coordinating HR initiatives across enterprise, including EGD
	    o Providing guidance, advice and coordinating specialist services to EGD
	    o Acting as the ultimate decision making authority for HR initiatives
	    o Developing HR policies and coordinate the delivery with EGD representatives on initiatives and issues
	• Develop Human Resources systems and processes to ensure that the management and business processes and systems are in place to facilitate effective, efficient and economic benefits.
	    o Identify human resources business issues and define scope of issue
	    o Research and identify alternatives to issue resolution
	    o Design systems and processes to support implementation of issue resolution
	    o Coordinate and facilitate the implementation of the systems and processes
	    o Develop system transition plans for EGD
	    o Provide mentorship and guidance/feedback on individual development plans/performance of EGD HR Director
	
	<u>Enterprise Security Department</u>
	The Human Resource Advice service provides research, expertise and support to internal initiatives. This includes support related to policy and systems

development, personnel management, and adherence to regulatory and legislative requirements. The Enterprise Security Department supports this service by being responsible for gathering, analyzing, and assessing information related to the security and protection risks that can adversely affect the security and safety of personnel.

Examples of activities related to the provision of the service:

- Assists Human Resources in the investigation of allegations of breach of the Business Code of Conduct including harassment and workplace violence
- Develops and maintains the Human Resource Protection Program for International travelers which includes risk assessments, security briefings (Duty to Warn) and security mitigation countermeasures commensurate with the risk (Duty to Protect).

Service Recipient: Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$30,011
Corporate HR	$171,768
Enterprise Security	$0
Total	**$201,779**

Expected Deliverables

- Support EGD's internal HR operations with research, insights and knowledge to support EGD's management in making informed business decisions
- Support EGD's HR Director regarding development planning and performance feedback/coaching

Quantity and Quality of Service

- On demand access to expertise and reliable HR advice to address EGD's business issues
- Executive mentoring/development planning support for EGD's HR Director

Authorized Signature

Mr. Marc Weil
Director Human Resources
Enbridge Gas Distribution

March 2, 2012
Date

21. Industry Relations & Corporate Social Responsibility (CSR)

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Industry Relations & CSR service provides the required EGD representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry.</td></tr>
<tr><td>Services Identified by Department</td><td><u>People and Partners Department</u>
The Industry Relations & CSR service provides the required EGD representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry. The People and Partners Department supports this service by providing the required representation with community stakeholder and interest groups, specifically related to, but not exclusive to educational institutions, environmental interest groups, health and safety organizations, officials and committees and various industry associations.

Examples of activities related to the provision of the service include:
• Responsible for the development, implementation and monitoring of the Corporate Social Responsibility programs and initiatives
• Establish, implement and measure the objectives and targets for corporate social responsibility performance including, but not exclusive to
    o Business ethics and transparency
    o Environment, health and safety
    o Stakeholder relations
    o Employee Relations
    o Human Rights
    o Community Investment
• Alignment of Corporate Social Responsibility initiatives, strategy and policies to annual and long-range strategic plans
• Review and approval of Corporate Social Responsibility project concepts and for funds
• Compare and benchmark corporate social responsibility performance against Dow Jones sustainability index
• Development and production of the Corporate Social Responsibility report

<u>Public and Government Affairs Department</u>
The Industry Relations & CSR service provides the required EGD representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry. The Public and Government Affairs Department supports this service by liaising with customers and special interest groups with respect to EGD's position on issues and initiatives in EGD customer communities.

Examples of activities related to the provision of the service include:
• Coordinate and deliver the company's Corporate Social Responsibility Program of stakeholder relations and production of the CSR annual report which includes:
    o EGD disclosures on environment, health and safety and social performance
    o Participating in industry associations such as CEPA and Energy Council of Canada, many of which deal with issues and operations that affect central Canada including Ontario

<u>Industry Associations Department</u>
This relates to the membership of the board members to various external industry associations. The Industry Association Department forms part of the CEO.</td></tr>
</table>

Examples of activities related to the provision of the service include:

- Pay for membership of the board members to various external industry associations

New Ventures Department

The Industry Relations & CSR service provides the required EGD representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry. The New Ventures Department supports this service by providing the required representation with community stakeholder and interest groups.

Examples of activities related to the provision of the service include:

- Responsible for the development, implementation and monitoring of the Corporate Social Responsibility programs and initiatives
- Attends, and presents at industry and community functions
- Interacts directly with media on consumer and company matters
- Establish, implement and measure the objectives and targets for corporate social responsibility performance including, but not exclusive to
  - Business ethics and transparency
  - Environment, health and safety
  - Stakeholder relations
  - Employee Relations
  - Human Rights
  - Community Investment
- Alignment of Corporate Social Responsibility initiatives, strategy and policies to annual and long-range strategic plans
- Review and approval of Corporate Social Responsibility project concepts and for funds

Enterprise Security Department

The Industry Relations & CSR service provides EGD the representation to major energy stakeholders e.g. suppliers, industry associations, and other energy companies in the energy industry. The Enterprise Security Department supports this service by being an active participant in Industry relation building and is a member of the National Energy Security Practitioners – an association of security professional from major Canadian and US energy companies.

Examples of activities related to the provision of the service include:

- Enterprise Security is responsible for production of the quarterly CSR report related to EGD initiatives and assignments.

Service Recipient:	Ms. Debbie Boukydis, Director Public and Government Affairs, Enbridge Gas Distribution Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
People and Partners	$22,987
Public & Government Affairs	$360,522
Industry Associations	$856
New Ventures	$0
Enterprise Security	$0
Total	**$384,365**

Expected Deliverables

	• Support and present EGD's interests to specific external stakeholders groups such as customer, industry and community groups that EGD would not have access to if it was a standalone entity • Provide CSR Report
Quantity and Quality of Service	
	• Access to special interest groups relevant to EGD • Positive interactions with special interest groups
Authorized Signature	
	Debbie Boukydis Ms. Debbie Boukydis Director Government and Public Affairs Enbridge Gas Distribution March 26, 2012 Date

22. Insurance Claims Support, Strategy and Management

Service Description	
Service Definition:	The Insurance Claims Support, Strategy and Management service is responsible for the general administration of insurance policies for EGD. Insurance policies implemented and managed by this service include liability, property, political risk, automobile, directors and officers liability, fiduciary and crime insurance.
Services Identified by Department	**CFO Department** The Insurance Claims Support, Strategy and Management service is responsible for the general administration of all insurance policies for EGD. Insurance policies implemented and managed by this service include liability, property, political risk, automobile, directors and officers liability, fiduciary and crime insurance. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial affairs. Examples of activities related to the provision of the service include: • Further to the insurance policies listed above, insurance specific to EGD includes Control of Well and other insurance policies as may be needed by EGD • Support negotiation of insurance premiums at renewal process of insurance policies **Risk Insurance Department** The Insurance Claims Support, Strategy and Management service is responsible for the provision of claims consulting and processing to ensure all claims are dealt with in an effective manner, as well as for the general administration of all insurance policies for EGD. Insurance policies implemented and managed by this service include, but are not limited to, liability, property, political risk, automobile, directors and officers liability, fiduciary and crime insurance. The Risk Insurance Department supports this service by working with insurance companies and law firms to assist EGD with large claims settlement, as well as by identifying and implementing programs which ensure the insurance requirements are met. Examples of activities related to the provision of the service include: • Provide claims consultation and guidance on material claims • Provide strategic direction to the EGD Operations Risk & Insurance function with respect to claims management • Liaise with EGD and independent legal counsel, and insurance expertise in support of large claim settlement processes • Liaise with insurance companies and law firms to assist EGD with claims settlement processes, as well as claims where the insurance deductible may be reached. • Further to insurance policies listed above, insurance specific to EGD includes Control of Well and other insurance policies as may be needed by EGD • Identify EGD specific insurance requirements, including regulatory compliance issues • Compile EGD data into overall EI insurance submission which is used by insurance companies for calculating insurance premiums costs • Select insurance vendors and negotiation of all insurance policies • Placement and maintenance of policies to ensure material changes to business operations are manifested in the appropriate levels of insurance coverage • Provide proof of insurance documentation to EGD • Provide formal Risk and Insurance Management Policy as available on

internal portal (E-link)

- Contract review process to establish consistency in standard terms & conditions for all insurance and indemnification clauses for all contracts for service agreements. Assist in the contract review of large contracts on as needed basis
- Liaise with EGD insurance groups on miscellaneous insurance matters
- Coordinate and manage 3rd party periodic loss control and risk control surveys to ensure insurance providers are aware that appropriate health and safety requirements are met
- Provide guidance and oversight to Enbridge off-shore re-insurers utilized to provide EGD with cost effective insurance coverage
- Provide placement of bonds and bonding and specific insurance policies (i.e. Builders' Risk) for construction projects, as required
- Forecast future insurance requirements and related expenditures for long range strategic planning, budgets and annual forecasts

Enterprise Risk Department

The Insurance Claims Support, Strategy and Management service is responsible for the general administration of all insurance policies for Enbridge Inc. and all of its affiliates. Insurance policies procured and managed by this service include general liability, property, political risk, control of well, automobile, aviation liability, directors and officers liability, fiduciary liability, crime coverage, professional liability and bonds. The Enterprise Risk Department supports this service by providing leadership and strategic support.

Examples of activities related to the provision of the service include:

- Support development of overall insurance strategies, including appropriate risk retention levels
- Support negotiation of insurance premiums and coverage terms and conditions
- Manage Risk Management department administratively

Service Recipient: Mr. Jamie Milner, Vice President Pipeline Integrity & Safety, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CFO	$29,314
Risk Insurance	$50,724
Enterprise Risk	$28,202
Total	**$108,240**

Expected Deliverables

- Minimize denied, delayed or reduced settlements on claims
- Present and manage EGD's insurance claims with the underwriting companies
- Provide advice on how to reduce claims
- Provide advice on policy coverage requirements
- Develop a customized insurance strategy, negotiate with underwriters and ensure a comprehensive policy is in place to maximize coverage at a cost lower than EGD would be able to achieve on its own (Note 1: EGD periodically engages an independent broker to perform an insurance program review for adequacy of coverage and costs competitiveness)
- Provide EGD's management with advice designed to support the successful development and implementation of the Insurance Management strategy

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Quantity and Quality of Service	
	• On demand access to support • Positive Claims experience • Reduced policy costs • Comprehensive policies meeting EGD's needs at a competitive price (see Note 1 above)
Authorized Signature	
	Mr. Jamie Milner Vice President Pipeline Integrity & Safety Enbridge Gas Distribution Mar 2/12 Date

24. Investor Services

Service Description	
Service Definition:	The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments.
Services Identified by Department	**<u>CEO Department</u>** The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The CEO Department supports this service by providing senior leadership representation and support to meetings attended by current and future lenders. Examples of activities related to the provision of the service include: • Maintain institutional investor and investment analyst relationships, as well as with other related agencies (i.e. Exchanges, security commissions, credit rating agencies, etc.) • Communicate EGD's financial condition and strategy to investment community through annual and quarterly reports, the annual general meeting, earnings calls, investor road shows and direct contact with existing and potential investors **<u>CFO Department</u>** The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The CFO Department supports this service by providing senior leadership representation and support to meetings such as those related to the annual general meeting and quarterly analyst calls, as well as to meetings and road shows with institutional investors. Examples of activities related to the provision of the service include: • Communicate EGD's financial condition and strategy to investment community through annual and quarterly reports, earning's calls, investor road shows and direct contact with existing and potential investors • Maintain institutional investor and investment analyst relationships, as well as with other related agencies, i.e., exchange (TSX), security commission (OSC), credit rating agencies (S&P, Moody's, Dominion Bond Rating Service and Dun & Bradstreet) • Conduct investor road shows every month except for January • Conduct quarterly analyst calls at which a large percentage of the questions are related to EGD • Report quarterly to credit rating agencies • Provide leverage with the banks to achieve lowest debt pricing, including the cost of short term commercial paper **<u>People and Partners Department</u>** The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The People and Partners Department supports this service by maintaining compliance to corporate governance guidelines and standards for exchanges, credit agencies and securities regulations.

Examples of activities related to the provision of the service include:

- Attends and presents at investor relations meetings
- Ensure compliance to guidelines or standards based on the exchanges , credit agencies under which EGD credit worthiness is rated, and the jurisdictions in which EGD operates. Specific entities include
    - TSX
    - Moody's and Standard and Poor's credit agencies
    - Canadian securities regulators

Corporate Secretarial Department

The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The Corporate Secretarial Department is responsible for supporting this service by providing legal, paralegal and administrative services.

Examples of activities related to the provision of the service include:

- Activities for Shareholders
    - Report and verify corporate governance and accountability
    - Coordinate the Annual Meeting of Shareholders
    - Manage shareholder business
        - Issue identification and clarification
        - Liaise with transfer agent
        - Maintain shareholder records
        - Voting policies and procedures (traditional and electronically)
- Maintain stock exchange listing on TSE
- Liaise with stock exchange and securities commission regarding compliance

Investor Relations Department

The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The Investor Relations Department provides support to this service by acting as the primary point of contact for all investor and analyst related inquiries and is responsible for coordinating and managing all investor communication activities (primarily with investment analysts).

Examples of activities related to the provision of this service include:

- Coordinate annual general meetings
- Coordinate quarterly earnings calls, media calls and other investor related communications; including collection, organization, construction and preparation of all presentation materials
- Monitor compliance with fair disclosure laws of Canada
- Maintain investor analyst, institutional and financial media contacts
- Respond to all customer and analyst inquiries
- Maintain and update investor related information on the Enbridge website on a daily basis. The website is the main portal of information for the investors

Treasury Department

The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The Treasury Department provides support to this service by maintaining relations with investors and investment analysts (primarily debt investors and investment analysts) to ensure the markets are advised of EGD's current and anticipated financial positions.

Examples of activities related to the provision of the service include:

- Prepare presentations and credit analysis for credit rating agencies, auditors, investments banks, institutional investors, debt holders and fixed income analysts
- Meet with investors and stakeholders to optimally present the financial condition of EGD
- Provide support for fixed income investment road shows and direct investor inquiries

Public and Government Affairs Department

The Investor Services service ensures that investors are fully informed of EGD's business objectives, strategy, financial performance and condition for the purpose of maintaining confidence in their current investments. It is a critical component of the capital market financing and access processes. The Public and Government Affairs Department supports this service by providing advice relating to external financial communications and maintaining media contacts for coordinating news releases and other communications.

Examples of activities related to the provision of the service include:

- Participate in Corporate disclosure process (e.g. CEO and CFO financial statement certification), particularly as it relates to financial communication, material disclosure, news releases, websites and publication of annual and quarterly reports

Service Recipient: Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$475,248
CFO	$69,404
People and Partners	$40,433
Corporate Secretarial	$118,346
Investor Relations	$55,854
Treasury	$60,598
Public & Government Affairs	$63,954
Total	**$883,837**

Expected Deliverables

- Develop and maintain investment community confidence in EGD
- Coordinate the dissemination of relevant business, strategic, financial and operational information

Quantity and Quality of Service

- Timely and relevant disclosures
- Appropriate external stakeholder segmentation
- Relevant messaging to each segment
- Effective communication channels: i.e. conference calls, media releases, investor road shows and general meetings

Authorized Signature

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution	Mar 2, 2012 Date

25. Legal Advice

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to matters such as contracts, litigation, regulatory proceedings and various EGD initiatives.</td></tr>
<tr><td>Services Identified by Department</td><td>

<u>Corporate Law Department</u>
The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to contracts, litigation, regulatory proceedings and various EGD initiatives. The Corporate Law Department supports this service by providing expertise and advice on legal issues and assisting with the development of governance related policies.

Examples of activities related to the provision of this service include:

Monitoring changes in federal legislation and identifying suggested changes to corporate policies (as noted below)
Drafting and setting EGD policies regarding items such as:

Compliance
Whistleblower procedures
Statement on Business Conduct
Internet policies
Record retention procedures, including electronic records discovery initiatives
Privacy laws
Crisis management

Coordinate and manage the selection process for certain external law firms retained by EGD

<u>Corporate Secretarial Department</u>
The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to continuous disclosure and securities law compliance, corporate governance, board and board committee matters. The Corporate Secretarial Department supports this service by providing legal expertise, paralegal and administrative services to the EGD Board of Directors and Audit, Finance & Risk Committee (“AFRC”).

Examples of activities related to the provision of the service include:

Legal advice in support of press releases, speech and publication review related to the activities of EGD’s Board and the AFRC
Disclosure committee – Provide advice to the EGD Disclosure Committee, thereby fulfilling a governance oversight role for EGD’s Board and for management
Legal advice and guidance with respect to EGD’s continuous disclosure obligations under applicable securities laws (e.g. quarterly and annual Financial Statements and Notes, Management’s Discussions and Analysis and the Annual Information Form)

<u>Executive VP Corporate Law Department</u>
The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to contracts, litigation, regulatory proceedings and various EGD initiatives. The Executive VP Corporate Law Department supports this service by providing executive level expertise and guidance as well as overall direction for significant compliance and governance initiatives.
</td></tr>
</table>

Examples of activities related to the provision of the service include:

- Managing the efforts of direct reports, and external legal counsel to reduce costs and risk, to increase functionality of the corporate secretarial services for the benefit of EGD, and to improve and enhance EGD's corporate image and key relationships by a thoughtful and coordinated approach to the public, shareholders, board members, regulators and to other key stakeholders
- Support the EGD Board and AFRC in connection with required legal matters for the benefit of EGD (including corporate governance and reporting issuer compliance)
- Setting corporate policies for the benefit of EGD regarding items such as:
    - Compliance
    - Whistleblower procedures
    - Statement on Business Conduct
    - Internet policies
    - Record retention procedures
    - Privacy laws
    - Crisis management
- Determine and implement required training programs to enhance EGD's corporate governance and transparency for matters such as whistleblower procedures, fraud awareness and prevention, and privacy protection.
- Coordinate and manage the selection process for certain external law firms retained by EGD
- Provide advice and counsel to EGD for legal matters related to corporate finance and public disclosure
- Monitor the state of compliance with assistance of the relevant departments in EGD, including conducting necessary investigations and reviews into complaints and issues of non-compliance
- Chair an enterprise wide committee including EGD and corporate representatives, which identifies and deals with risk mitigation and compliance matters generally to the overall benefit of EGD
- Update and revise as necessary the Enbridge Statement on Business Conduct, together with other corporate ethics policies and programs for the benefit of EGD
- Provide executive level guidance and advice regarding the structure of EGD's Law Department

Enterprise Security Department

The Legal Advice service provides access to legal precedents, research material and legal experts providing advice related to contracts, litigation, regulatory proceedings and various internal initiatives. The Enterprise Security Department supports this service by providing expertise and advice on mitigation of enterprise security risks and conducting investigations where warranted to ensure the protection of EGD's assets and employees.

Examples of activities related to the provision of the service include:

- Reports to the Vice President, General Counsel & Chief Compliance Officer on EGD security matters
- Accountable for strategic oversight of all security and protection policies and programs including developing, influencing and directing a security and protection strategy for EGD
- The security and protection strategy includes the protection of organizational reputation, the uninterrupted reliability of the technical infrastructure and normal business processes, protection of physical and financial assets, and the safety of employees.
- In collaboration with EGD's management, develops and implements EGD's security and protection strategy directly related to identified risks.

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

The strategy should outline in detail the plans to prevent and prepare for an adverse event.

- Provides advice and guidance to EGD Corporate Security staff with respect to strategies for protection of the physical assets (cash, facilities, equipment), intangible assets (reputation, intellectual property, and trade secrets), and the people (management, directors, employees, customers, contractors and others) of the organization.
- Responsible and accountable for ensuring that EGD is prepared for the possibility of a catastrophic event or related significant security incident. This involves the administration of training plans, programs, and exercises. Responsible for regular review and evaluation of the organizational readiness plan in the event of a security related event or emergency.
- In case of a security related emergency or an incident, responsible for coordinating efforts to restore the critical systems and provide the facilities required for EGD to function.
- Provides leadership and support to EGD's executive team to ensure risks are made known to senior management and the Board of Directors.

Service Recipient: Mr. Mark R. Boyce, Vice President, Law & Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Corporate Law	$353,497
Corporate Secretarial	$38,973
Executive VP Corporate Law	$121,926
Enterprise Security	$0
Total	**$514,396**

Expected Deliverables

- Support EGD staff with legal research, insights and knowledge leveraging the collective expertise of Enbridge Inc.
- Facilitate the acquisition of cost effective external legal services through the negotiation of volume discounts with national law firms utilized by EGD.

Quantity and Quality of Service

- On demand access to expertise and reliable legal advice and knowledge
- Effective and current legal research, reporting and access to up to date legal precedents.

Authorized Signature

Mr. Mark R. Boyce
Vice President, Law &
Information Technology
Enbridge Gas Distribution

March 21, 2012
Date

26. Planning, Management & Execution of Internal Audits

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Planning, Management and Execution of Internal Audits service is responsible for Audit program development for the execution of internal audits within EGD.</td></tr>
<tr><td>Services Identified by Department</td><td>
<u>CFO Department</u>
The Planning, Management and Execution of Internal Audits service is responsible for Audit program development for the execution of internal audits within EGD. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding financial affairs.

Examples of activities related to the provision of the service include:
Advise on the Annual Audit Plan
<u>Audit Services Department</u>
The Planning, Management and Execution of Internal Audits service is responsible for Audit program development for the execution of internal audits within EGD. The Audit Services Department supports this service by assuming responsibility for developing and coordinating the annual internal audit program.

Examples of activities related to the provision of the service include:

Audit program development and execution from a financial, compliance, operational and systems perspective

Ensure audit program alignment to long range plan and risk mitigation plan
Identify depts. and activities to audit
Set and validate audit materiality levels
Identify audit synergies across EGD and coordinate resources to minimize costs
Address issues and gaps in Audit process
Perform audits / tasks, which include

Financial Reporting Certification
Internal Controls Certification
External Audit Assistance Coordination
Statement of Business Conduct Review
D&O Liability Review
Treasury Systems
Cash Management
Debt & Equity Processes
Enterprise-wide Financial Systems
Khalix Consolidation Systems
Corporate Social Responsibility

Provide leadership for policy development
Coordinate functional and department stakeholders for the Audit
Review EGD audit plans and execution

Provide quality assurance
Highlight areas of concern
Recommend mitigation actions
Review audit findings and assist with development of reports

Provide counsel and leadership on internal control, risk management and governance issues and report audit results to the Audit, Finance and Risk committee of EGD

</td></tr>
<tr><td>Service Recipient:</td><td>Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution</td></tr>
</table>

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Cost of Service

Department	Service Charge
CFO	$32,426
Audit Services (Calgary)	$159,102
Total	**$191,528**

Expected Deliverables

- Provide guidance to EGD to ensure it has an internal audit plan that aligns with the strategic and risk mitigation plan and leverages the enterprise expertise and supporting resources of the organization
- Ensure alignment of external audit and internal audit to minimize business disruptions and leverage the expertise of available resources
- Provide advice on how to reduce external audit costs
- Provide advice on how to improve controls and efficiencies

Quantity and Quality of Service

- Timely, effective, low cost internal and external audit
- On demand access to financial, accounting and auditing resources, knowledge and expertise
- On demand support and leadership from Audit Services on specific audit mandates

Authorized Signature

Mr. Narin Kishinchandani
Vice-President Finance
Enbridge Gas Distribution

Mar 2, 2012
Date

27. Portal Suite Operations and Technical Support

Service Description	
Service Definition:	The Portal Suite provides a reliable platform for presenting "web based" content to employees and business partners. The value of this service is: • A central environment for information provided to employees • A central "launch" point for applications, • A central location for content storage and retrieval, • Development standards that ensure reliability and consistency • Consistent and manageable access and security for employee content • The Portal Suite consists of several related applications. The primary applications are the eLink (Sharepoint), eSource (Oracle Portal), Microsoft SharePoint and Open Text Livelink (document and records management service). As well, the Portal Suite consists of a series of supporting connecting services and customized applications. EGD requires this service to enable easy employee access to all relevant data.
Services Identified by Department	**CIO Department** The Portal Suite provides a reliable platform for presenting "web based" content to both employees and business partners. The CIO Department supports the Portal Suite Operations and Technical Support service by providing strategic guidance to the technical support teams. Examples of activities related to the provision of the service include: • Vendor management, • Operational management services, • Systems management services • Project management services, • Security and IT risk assessment services, • Technical architecture planning services • Portal Suite governance. **Corporate IT Operations Department** The Corporate IT Operations Department supports the Portal Suite Operations and Technical Support service by providing the enterprise coordination of projects, governance and performance management for the Portal Suite. Examples of activities related to the provision of the service include: • Supporting the management of support & maintenance service level agreements, • Conducting research on emerging Portal Suite technologies for the purpose of improving support for business operational and strategic objectives, • Working with stakeholders to identify required enhancements or changes to existing systems, • Developing business case, project charter, project plan and other required project documentation; including securing project approval • Development of risk management plans, and coordinating related risk mitigation activities • Developing business cases to modify, expand or acquire functionality, • Working with the EGD Portal Suite departments to ensure proper client training (eLink). • Managing and monitoring Portal Suite projects through to completion • Gathering, analyzing and reporting Portal Suite statistics, to understand current usage and traffic patterns for the portal suite. This will allow for

pro-active planning and changes to content and applications based on past usage and trends.

- Working with the CIO Department to help manage vendor relations.

Service Recipient: Mr. Henry Wong, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$167,529
Corporate IT Operations	$163,352
Total	**$330,881**

Expected Deliverables

- Ensure availability of the infrastructure and Portal Suite to support employee access to all relevant data
- Provide user support as required
- Portal Suite statistical reports
- Provide an efficient and effective intranet portal. This portal is used as communications tool and as a robust application delivery and presentation platform.
- Ensuring the following activities are performed to EGD's satisfaction:
- Vendor management,
- Operational management services,
- Project management services,
- Security and IT risk assessment services,
- Technical architecture planning services
- Portal Suite governance.

Quantity and Quality of Service

- Continuous and uninterrupted access to Portal Suite
- Timeliness, accuracy and integrity of data
- On demand user support
- Ensure that SLA's are in place to govern the service delivery commitments associated with the Portal Suite.
- Provide EGD with a portal that it can fully leverage, this includes understanding future technical and functional possibilities and linking them to business direction.
- Ensure users needs and concerns are integrated into future development and enhancement plans.
- Ensure that projects follow a rigorous documentation process.
- All changes to the Portal Suite need to be cost and business value justified.
- Ensure that all users and super-users of the Portal Suite are adequately trained to encourage proper use and adoption of the portal suite platform.

Authorized Signature

RB

Mr. Henry Wong
Director Information Technology
Enbridge Gas Distribution

May 7, 2012
Date

28. Rate Regulated Entity Support

Service Description

Service Definition: The Rate Regulated Entity Support service is responsible for supporting EGD's rate regulated entities and unique services pertaining to their regulatory proceedings and rate setting matters.

Services Identified by Department

Corporate Controller Department

The Rate Regulated Entity Support service is responsible for supporting EGD's rate regulated entities and unique services pertaining to its regulatory proceedings and rate setting matters. The Corporate Controller Department supports this service by managing the rate-regulated cost allocation methodology and ensuring its application according to the governing regulations.

Examples of activities related to the provision of this service include:

- Coordinate and manage the corporate and regulatory cost allocation process
- Attend and provide testimony at regulatory hearings
- Provide research and analysis for regulatory support, as required

Treasury Department

The Rate Regulated Entity Support service is responsible for supporting EGD's rate regulated entities and unique services pertaining to their regulatory proceedings and rate setting matters. The Treasury Department supports this service by providing Corporate Treasury expertise in the preparation of rate hearings and planning for corporate finance, cash management, and financial risk related to regulatory issues.

Examples of activities related to the provision of this service include:

- Prepare rate case testimony and evidence
  - Address all corporate finance (interest rate, debt financing, etc.), cash management, risk management, access to capital, cost of capital, and transactional support issues through the preparation of evidence, interrogatory responses, and undertaking responses.
  - Develop any supporting material required or requested and answer general discovery questions.
  - Research past testimony, coordinate and address changes in policy.
  - Research and analyze current practices regarding corporate finance (interest rate, debt financing, etc.), cash management, risk management, access to capital, cost of capital, transactional support issues for EGD, both at the provincial and federal level,
- Attend and provide testimony at regulatory hearings when required
- Provide advice, research and analysis regarding all corporate finance (interest rate, debt financing, etc.), cash management, risk management, access to capital, cost of capital, and transactional support issues for special proceedings as they arise to assess potential impacts on EGD.
- Provide any other advice, research and analysis as requested by EGD

Service Recipient: Mr. Narin Kishinchandani, Vice-President, Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Corporate Controller	$44,923
Treasury	$208,981

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	Total	**$253,904**	
Expected Deliverables			
	• Support EGD's internal operations staff		
Quantity and Quality of Service			
	• On demand access to expertise and reliable advice • Continuous knowledge of EGD's operations and requirements • Continuous knowledge on topical and current regulatory accounting precedent research • Continuous knowledge on topical and current regulatory financing issues.		
Authorized Signature			
	Mr. Narin Kishinchandani Vice-President, Finance Enbridge Gas Distribution	Mar 2, 2012 Date	

29. Records and Information Management

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Records and Information Management service is responsible for the overall development, maintenance and dissemination of policies, procedures, and guidelines for the establishment and maintenance of the Records and Information Management Program.</td></tr>
<tr><td>Services Identified by Department</td><td><u>Enterprise Content Management Department</u>
The Records and Information Management service is responsible for the overall development, maintenance and dissemination of policies, procedures, and guidelines for the establishment and maintenance of the Records and Information Management Program. The Enterprise Content Management (ECM) Department supports this service by providing strategies, standards, tools, and project management. Specifically as it relates to information technology systems, the ECM department supports this service by developing and maintaining strong, reliable content management systems and solutions that effectively support the business. The systems portfolio that supports the Records and Information Management service includes Livelink, Enterprise Contracts Management and EnCase.

Examples of activities related to the provision of the service include:
Provide technical management and support for records and document management systems
Provide functional management and user support for records and document management systems
Develop and maintain system roadmaps for the evolution of document and records management systems in response to changing and emerging business needs
Support negotiation and administration of systems maintenance and consulting third party contracts
Provide assistance and advice to EGD on records and information management matters
Provide consultation and advice to EGD in support of document management system implementation projects
In partnership with business, develop and maintain folder structure following guiding principles as set by ECM and Records Management (RM)
In partnership with RM, link records retention schedule business rules to folder structure
Administer users (i.e. groups, permissions)
Administer the records management module of Livelink
Provide training on document and records management system functionality and business rules to system users
<u>Records Management Department</u>
The Records and Information Management service is responsible for the overall development, maintenance and dissemination of policies, procedures, and guidelines for the establishment and maintenance of the Records and Information Management Program. The Records Management Department is responsible for the overall development, maintenance and dissemination of policies, procedures, and guidelines for the establishment and maintenance of Enbridge (physical and electronic) records. This includes supporting records management requirements by providing strategies, policies, standards, tools, and program management including compliance monitoring.

Examples of activities related to the provision of the service include the following</td></tr>
</table>

initiatives:

- Provide leadership and direction in the establishment of the RM Program Roadmap
- Develop, distribute and maintain policies, procedures and guidelines for records and information management
- Maintain the Enterprise Records Retention Schedule which meets business needs as well as applicable laws, regulations and industry standards for the benefit of EGD
- Develop and monitor compliance with records disposition policies and practices
- Communicate, educate and train EGD employees on records management obligations, purpose, principles and minimum compliance requirements
- Provide assistance and advice to EGD on records management matters
- Support negotiation and administration of any records management third party contracts

Records Management Department
In partnership with the ECM team:

- Provide consultation and advice to EGD on document management improvement initiatives prior to implementing records and document management systems, both physical and electronic
- Provide consultation and advice to EGD in support of document management system implementation projects
- Provide functional management and user support of records and document management systems
- In partnership with business, develop and maintain folder structure following guiding principles as set by ECM and RM
- Link records retention schedule business rules to folder structure
- Administer users (i.e. groups, permissions)
- Administer the records management module of records management systems
- Provide training on document management system functionality and document management business rules to system users (electronic documents)
- Provide training on document management system functionality and records management business rules to system users (physical records)
- Develop, maintain and disseminate the document management system Framework to support the Records Management Program objectives in the management of electronic information.

Service Recipient: Mr. Mark R. Boyce, Vice President Law & Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Enterprise Content Management	$395,194
Records Management	$143,158
Total	**$538,352**

Expected Deliverables

- Ensure that all EGD staff have secure storage of, and access to, operational information through a variety of internal sources

Quantity and Quality of Service

- Continuous and uninterrupted access to stored records and documentation;

	• Ensure access to information technology systems to support records management practices; • Ensure that sound records discovery practices are developed and implemented; • Ensure availability of advice regarding best practices for records and information management
Authorized Signature	
	March 21, 2012 Mr. Mark R. Boyce Vice President, Law & Information Technology Enbridge Gas Distribution Inc. Date

30. Risk Assessment and Management

Service Description	
Service Definition:	The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies.
Services Identified by Department	**CEO Department** The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The CEO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial and operational affairs. Examples of activities related to the provision of the service include: • Provide guidance and oversight to all risk management policies and monitor financial and non-financial mitigation activities to ensure prudent measures are in place for EGD **CFO Department** The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial affairs. Examples of activities related to the provision of the service include: • Provide guidance and oversight to all risk management policies and monitor financial and non-financial mitigation activities to ensure prudent measures are in place for EGD **Corporate Controller Department** The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The Corporate Controller Department supports this service by assuming responsibility for coordinating the annual risk assessment exercise with EGD. The corporate risk assessment provides insight into all forms of risk that may be encountered in the course of conducting day-to-day business. Examples of activities related to the provision of the service include: • Develop and coordinate the Corporate Risk Assessment process and all resources required to support the assessment • Develop and coordinate effective internal controls • Identify risk types and collect the required data to describe, measure and rank to determine potential for occurrence and impact • Communicate Corporate Risk Assessment findings to the EGD Executive Management Team and Board of Directors **Audit Services Department** The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The Audit Services Department supports this service by identifying, developing and implementing financial risk mitigation controls and strategies.

Examples of activities related to the provision of the service include:

- Develop risk mitigation strategies and control systems
- Identify and advise on financial compliance and operational risk areas
- Develop risk mitigation plan
    - Set and validate risk materiality levels
    - Quantify risk exposure and develop mitigation strategies and alternatives
    - Present recommendations to the EGD Audit, Finance and Risk Committee (AFRC) for approval
- Coordinate implementation of risk mitigation strategies
- Measure, monitor and report on current or potential future financial compliance and operational risks
- Update risk mitigation plan based on findings

Enterprise Risk Department

The Risk Assessment and Management service is responsible for identifying corporate risks, supply and demand risks, operational risks, and external risks, understanding their implications and developing mitigation strategies. The Enterprise Risk Department supports this service by assuming responsibility for assessing, advising on and executing transactions related to mitigating the financial market risk. In addition, the Enterprise Risk Department monitors the credit risk exposure and reports all risk exposures to the EGD Executive Management Team, EGD Executives and EGD's Audit, Finance and Risk Committee.

Examples of activities related to the provision of the service include:

- Identify and advise on interest rate risk, foreign exchange risk, commodity risk, credit risk, and execution risk
- Quantify risk exposure and develop mitigation strategies and alternatives
- Present recommendations to EGD's Audit, Finance and Risk Committee (AFRC) for approval
- Identify and execute financial contracts (if required) for hedging purposes
- Measuring, monitoring and reporting on current or future financial risk
- Research credit rating and financial strength of customers and suppliers
- Determine and assign credit limits to customers and obtain credit enhancements
- Monitor credit exposure
- Measuring, monitoring and reporting on current or future financial risk
- Review and monitor compliance to risk control policies and procedures including compliance with hedge accounting guidance
- Calculate the mark-to-market and fair market values of financial instruments used in all financing activities, specifically for hedging purposes
- Measure, monitor and report compliance findings to Audit, Finance and Risk committee of EGD Board
- Process the contracts and settlements of financial and physical transactions
- Manage the on-going maintenance and support of the risk management information technology system

Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution
Cost of Service	

Department	Service Charge
CEO	$30,646
CFO	$17,139
Corporate Controller	$0
Audit Services (Calgary)	$23,728
Enterprise Risk	$806,948
Total	**$878,461**

Expected Deliverables

- Identify all material financial, operational and economic risks associated with EGD's business
- Prepare a Risk Assessment Report
- Develop and execute risk mitigation strategies that support EGD leadership in making informed business decisions

Quantity and Quality of Service

- Low risk profile
- Minimal business interruption

Authorized Signature

Nkishinchandani

Mr. Narin Kishinchandani
Vice-President Finance
Enbridge Gas Distribution

Mar 2, 2012
Date

31. Strategic Planning

Service Description	
Service Definition:	The Strategic Planning service coordinates the development of EGD's vision and related operational activities and financial impacts delivered through the long-range planning process and document.
Services Identified by Department	**<u>CEO Department</u>** The Strategic Planning service coordinates the development of EGD's vision and related operational activities and financial impacts delivered through the long-range planning process and document. The CEO Department provides support to this service by setting the overall organizational strategy and provides guidance. Examples of activities related to the provision of the service include: • Provide vision, expertise and leadership to the development of the EGD long range plan (5 and 10 year plan) • Advise on all other aspects of the long-range plan including opportunity identification and selection, visioning exercises, tactical planning, etc. • Provide final authority on the long range plan prior to approval by the EGD Board of Directors • Maintain active involvement in securing EGD executive and Board of Directors support for the long range plan **<u>Treasury Department</u>** The Strategic Planning service coordinates the development of EGD's vision and related operational activities and financial impacts delivered through the long-range planning process and document. The Treasury Department provides support to this service by providing analytical financial support. Examples of activities related to the provision of the service include: • Forecast the long-term financing needs based on long range plan and budget plans **<u>Enterprise Risk Department</u>** The Strategic Planning service coordinates the development of EGD's vision and related operational activities and financial impacts delivered through the long-range planning process and document. The Enterprise Risk Department provides support to this service by providing analytical financial support. Examples of activities related to the provision of the service include: • Create a forecast for interest rates, foreign exchange rates and commodity prices for the term of the long range plan
Service Recipient:	Mr. Arunas Pleckaitis, Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$267,256
Treasury	$0
Enterprise Risk	$60,634
Total	**$327,890**

Expected Deliverables

- Senior level oversight and direction provided on long term strategies for EGD including opportunity identification, visioning and financial

	projections. This helps to ensure that the financing plan is in place and resources are available to support execution. • Annual strategic plan document for all EGD employees
Quantity and Quality of Service	
	• Availability of Corporate Planning group to produce EGD. Strategic Plan annually and communicated to all EGD employees by November Facilitate Senior Management Strategic Planning Workshop in February to discuss EGD s Strategic Plan issues • Availability of Budgetary and Controller support to ensure that Corporate Planning Standards are available in a timely fashion to support completion of the Long Range Plan in April • Articulate EGD strategic thrusts to the investment community via Enbridge Day, ensuring positive feedback from analysts on EGD documented strategies • Executable strategy (at a level of detail that allows EGD to execute)
Authorized Signature	
	Mr. Arunas Pleckaitis Vice-President Business Development & Customer Strategy, Enbridge Gas Distribution Mar 02/12 Date

32. Supply Chain Management

Service Description	
Service Definition:	The Supply Chain Management service is responsible for coordinating the enterprise-wide initiative to identify and implement procurement cost savings by applying strategic sourcing techniques for the benefit of EGD.
Services Identified by Department	**CFO Department** The Supply Chain Management service is responsible for coordinating the enterprise-wide initiative to identify and implement procurement cost savings by applying strategic sourcing techniques for the benefit of EGD. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding supply chain initiatives. Examples of activities related to the provision of the service: • Provide advice and guidance to Supply Chain Steering Committee, in which EGD is a member, in identification and development of supply cost management initiatives **Corporate Administration Department** The Supply Chain Management service is responsible for coordinating the enterprise-wide initiative to identify and implement procurement cost savings by applying strategic sourcing techniques for the benefit of EGD. The Corporate Administration Department supports this service by coordinating the enterprise wide initiative to identify and implement strategic sourcing initiatives through activities performed by the Supply Chain Steering Committee. The Supply Chain Steering Committee consists of procurement specialists from each principal Enbridge business unit, including EGD. Examples of activities related to the provision of this service include: • Assessment of the complete life-cycle of a commodity or service. Total life cycle cost representing the entire value chain, including design, implementation, maintenance, repair, replacement and decommissioning form the basis of the selection process • Identification of opportunities for procurement cost reductions and process efficiencies • Implementation of cost saving and efficiency opportunities • Management of Supply Chain RFP process including team formation, documentation, and vendor selection • Manage enterprise-wide vendor relationships and negotiations
Service Recipient:	Mr. Glenn Beaumont, Senior Vice President Operations, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CFO	$24,915
Corporate Admin.	$14,791
Total	**$39,706**

Expected Deliverables

- Exploitation of identified commodities to reduce the cost of ownership and improve performance, without compromising operational integrity
- Schedule, conduct and report on all results targeted for fiscal year

Quantity and Quality of Service

- Low cost procurement (lower cost structures than industry average)

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	• Measurable cost savings
Authorized Signature	
	Mr. Glenn Beaumont Senior Vice President Operations Enbridge Gas Distribution March 26/12 Date

33. Tax Reporting & Planning

Service Description	
Service Definition:	The Tax Reporting and Planning service is responsible for ensuring proper reporting of the tax positions in financial statements and tax returns and to ensure initiatives are implemented so that tax is minimized.
Services Identified by Department	**<u>CFO Department</u>** The Tax Reporting and Planning service is responsible for ensuring proper reporting of the tax positions in financial statements and tax returns and to ensure initiatives are implemented so that tax is minimized. The CFO Department supports this service by providing senior leadership, overall management guidance and advice regarding EGD's financial affairs. Examples of activities related to the provision of the service include: • Review tax strategy with respect to past tax related issues. Develop policy in regards to tax issues and tax fund planning • Review tax planning and the adequacy of tax provisions for all Enbridge entities and communicate recommendations to the Board of Directors charged with tax oversight accountability **<u>Tax Services Department</u>** The Tax Reporting and Planning service is responsible for ensuring proper reporting of the tax positions in financial statements and tax returns and to ensure initiatives are implemented so that tax is minimized. The Tax Services Department supports this service by providing tax expertise and assuming responsibility for developing, implementing, and reporting on tax strategies. Examples of activities related to the provision of the service include: • Provide research and information dissemination on certain tax matters including changes in tax policies, changes to GAAP and other issues to tax group and senior management • Review of financial statement disclosures related to tax items including the effective income tax rate reconciliation (oversee changes as appropriate to disclosure) • Providing advice on accounting treatment, related to new issues with a tax impact, in terms of the tax provision recorded in the general ledger • Ensure adequate communication of all tax planning initiatives and tax implications of projects within the tax group and that the tax returns accurately report these items. • Reporting to Audit, Finance & Risk Committee of the EGD Board of Directors regarding tax exposures and quarterly reporting of exposures to senior management in conjunction with provision review. Advise on appropriate provision for exposures in financial statements • Review of EGD tax return and provide advice • Prepare tax assumption memos and provide tax support for budget groups • Provide general tax advice and tax planning • Provide tax assistance re importation of Natural Gas
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CFO	$0

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

	Tax Services	$55,308
	Total	**$55,308**

Expected Deliverables

- Oversight and leadership provided to the EGD tax team

Quantity and Quality of Service

- On demand access to tax reporting
- Effective & topical tax reporting at a level of detail that allows EGD to execute

Authorized Signature

Mr. Narin Kishinchandani
Vice-President Finance
Enbridge Gas Distribution

Mar 2, 2012
Date

34. Total Compensation and Benefits

Service Description	
Service Definition:	The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs.
Services Identified by Department	**<u>CEO Department</u>** The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The CEO Department supports this service by providing senior leadership to compensation policy design and implementation. Examples of activities related to the provision of the service include: • Monitor and guide the compensation system to ensure company competitiveness and skill retention relative to market availability and needs **<u>People and Partners Department</u>** The Total Compensation and Benefits service is responsible for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The People and Partners Department supports this service by providing senior leadership to compensation policy design and implementation. Examples of activities related to the provision of the service include: • Identifies and brings forward compensation related recommendations to the EI Board Human Resource Compensation Committee, which set all compensation policies for EGD • Maintains fiduciary responsibility for the design and delivery of EGD's supplementary and regular pension plans and funding **<u>Corporate Human Resources Department</u>** The Total Compensation and Benefits service provides for the establishment of reward policy, strategy and programs including base pay (including job performance), performance based incentives (long term and short term incentive programs), benefits programs, pension programs and recognition programs. The Corporate Human Resources Department supports this service by providing HR expertise to the implementation of total reward programs. Examples of activities related to the provision of the service include: • Developing total rewards strategies for review, input and approval by the Human Resources Leadership Team (HRLT), Corporate Leadership Team and HRC of the Board of Directors • Provide specialized resources for guiding and conducting work for the development of base pay (including job evaluation), short term and long term incentives, benefits, pension perquisites and recognition programs • Provide guidance and advice on broad compensation issues **<u>Pension & Benefits Department</u>** The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The Pension & Benefits Department supports this service

by providing HR expertise and operational support to the development and implementation of pension and benefits programs and employee relations policies.

Examples of activities related to the provision of the service include:

- Coordinate and manage human resources policy issues, with support from legal, tax and corporate communications departments
- Employee pension and benefits plan design and governance
  - Recommend changes to pension and benefits
  - Steward the approval process through the Board of Directors approval process
  - Implement plan changes with carriers
- Managing external consultants (Actuarial and Management Consultants) for pension and benefit matters
- Responsible for the development of communication and education tools related to pension and benefits for dissemination by EGD to their employees
  - Pension and Benefits changes
  - Policy changes related to work hours, Statutory Holidays, Scholarship opportunities and Maternal/Paternal/Sick leave
- Identify and implement new organizational programs (e.g. Web enabled financial planning and retirement tool)
- Manage the collection and analysis of external industry pension and benefit benchmarking data and the use of external consultants
- Manage the administration of executive benefits and retirement programs, including medical assessments
- Provide guidance and support to issues related to pension and benefits and governance for both internal initiatives as well as external relationships such as joint ventures and alliances
- Provide advice to EGD's HR departments related to the efficient design, management, and administration of pension & benefit plans.
- Provide research and support to identify pension plan & benefit alternative to support resolution to EGD issues

Total Compensation Department

The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The Total Compensation Department supports this service by providing HR expertise and operational support to the development, design, and implementation of compensation and performance programs.

Examples of activities related to the provision of the service include:

- Coordinate and manage human resources policy issues, with support from legal, tax and corporate communications departments
- Managing external consultants (Actuarial and Compensation Consultants))
- Identify and implement new organizational programs (e.g. Web enabled financial planning and retirement tool)
- Design job evaluation processes
- Manage the collection and analysis of external industry benchmarking data and the use of external consultants
- Design the compensation policies and programs, relating to
  - Base compensation and salary scale
  - Sales / commission based compensation
  - Retention and merit bonuses
  - Non-cash reward programs
- Manage the design and execution of the short term incentive program for executives and non-executives and the long term incentive program for

executives
    - Identification of enterprise wide financial and EGD specific operating and financial metrics
    - Develop and communicate the policies, process and guidelines for performance program and succession ratings including hot skills identification
    - Oversee the review of performance ratings and approval (through the Board of Directors) and administration of the granting of stock options and performance stock units
- Responsible for the development of supporting processes and policies related to
    - Promotion
    - Transfers
    - Job reclassification
    - Temporary Pay
    - Moving / Transfer
- Manage the administration of executive compensation programs, including stock option and PSU administration and ancillary compensation program administration and parking
- Provide guidance and support to issues related to compensation and governance for both internal initiatives as well as external relationships such as joint ventures and alliances
- Provide employee relocation support and guidance

Corporate Controller Department

The Total Compensation and Benefits service provides for the establishment of total employee compensation including base pay, performance bonuses (long term and short term incentive programs), benefits programs and job evaluation and performance programs. The Corporate Controller Department supports this service by providing the financial analysis and reporting, required to support the determination of short-term, long-term and success sharing bonuses for all EGD employees.

Examples of activities related to the provision of this service include:
- Establish performance metric targets (Enbridge Inc. Return On Equity; Affiliate Earnings, and Total Shareholder Returns)
- Provide annual and quarterly measurement and reporting of current and forecasted performance, including securing approvals from EGD President
- Liaise with Corporate Human Resources group on all matters related to financial performance and bonuses
- Conduct research and report on alternative bonus related performance metrics
- Provide ad hoc performance reporting and analysis

Service Recipient: Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CEO	$200,402
Group VP Corp. Resources	$249,040
Corporate HR	$159,379
Pension & Benefits	$0
Total Compensation	$1,108,782
Corporate Controller	$64,206
Total	**$1,781,809**

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

Expected Deliverables	
	• Support EGD by developing a competitive and innovative compensation, benefits and performance strategy
Quantity and Quality of Service	
	• Support EGD by developing a competitive and innovative compensation, benefits and performance strategy • Provide EGD management with policies, guidelines and resources designed to support the successful development and implementation of the compensation, benefits and performance strategy • Balance EGD's employee retention and personal development goals with fiscal responsibility and the interests of shareholders
Authorized Signature	
	Mr. Marc Weil Director Human Resources Enbridge Gas Distribution March 2, 2012 Date

General Expense

The following tables outline the general expense items directly allocated to EGD. These general expenses are agreed to (by written signature) by a representative of EGD.

A general expense is defined as a significant cost that benefits the Service Recipient, and requires allocation on a basis separate from the Primary Services because the driver of the cost is different, or because the cost is a large, third party cost. A list of the general expenses and the basis of allocation attributable thereto, are set out in RCAM.

Each table provides details on:

- The general expense item definition;
- The EGD representative responsible for agreeing to the service; and
- The EGD cost of the general expense item as calculated in the RCAM model.

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

35. Depreciation – Risk Management System

Service Description	
General Expense Definition:	Depreciation – Risk Management System contains the depreciation on the Openlink risk management system. Openlink is used by Treasury and Risk Management to manage risk on all physical commodity deals for EGD. It is also used to track and manage EGD risk on all financial hedges made against these physical commodity deals, including external and internal debt, inter-company loans and Interest Rate and Foreign exchange.
Service Recipient:	Mr. Narin Kishinchandani Vice President Finance, Enbridge Gas Distribution
Cost of Service	
	$64,951
Authorized Signature	
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2, 2012 Date

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

36. Direct EFS Charge

Service Description	
General Expense Definition:	The costs for supporting the Enterprise Financial Systems (EFS) are directly incurred by multiple affiliates for the purpose of delivering enterprise financial services. For allocation purposes, the participating affiliates' original budget allocations are notionally aggregated and the charges are calculated based on affiliate user count. The difference between this affiliate calculation and the affiliate's original budget allocation (debit or credit) is allocated to the affiliate.
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution
Cost of Service	
	($2,314,784)
Authorized Signature	
	Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Date: Mar 2, 2012

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

37. Directors Fees and Expenses

Service Description	
General Expense Definition:	The Directors fees and expenses comprises all fees paid to directors of EI's Board, including conducting Board activities and liaisons with members of EI senior executive.
Service Recipient:	Mr. Narin Kishinchandani, Vice-President Finance, Enbridge Gas Distribution
Cost of Service	
	$744,819
Authorized Signature	
	Nkishinchandani Mr. Narin Kishinchandani Vice-President Finance Enbridge Gas Distribution Mar 2, 2012 Date

Direct Charges

The following tables outline the direct charge items directly allocated to EGD. These direct charges are agreed to (by written signature) by a representative of EGD.

A direct charge is defined as a service related item separately included in the Service Providers budgets that can be specifically attributed to the service Recipient without loading. A list of the direct charges, and the basis of allocation attributable thereto, are set out in RCAM.

Each table provides detail on:

- The direct charge item definition;
- The EGD representative responsible for agreeing to the service; and
- The cost of the general expense item as calculated in the RCAM model.

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

38. EGD Stock Based Compensation

Service Description	
General Expense Definition:	The Stock Based Compensation department contains costs for the expense related to the granting of Long-Term Incentives to Manager-level and above staff within Enbridge Gas Distribution. Long-term incentives are also granted to certain lower level staff on a discretionary basis.
Service Recipient:	Mr. Marc Weil, Director Human Resources, Enbridge Gas Distribution and Mr. Narin Kishinchandani, Vice President Finance, Enbridge Gas Distribution
Cost of Service	
Service Price:	$7,549,229
Authorized Signature	
	Mr. Marc Weil Director Human Resources Enbridge Gas Distribution March 2, 2012 Date Mr. Narin Kishinchandani Vice President Finance Enbridge Gas Distribution Mar 2, 2012 Date

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2012

39. Insurance Premiums

Service Description	
General Expense Definition:	Costs include insurance premiums for liability, crime, property, automobile, and fiduciary policies held for Enbridge Inc. and its affiliates.
Service Recipient:	Mr. Jamie Milner, Vice President Pipeline Integrity & Safety, Enbridge Gas Distribution
Cost of Service	
Service Price:	$8,483,868
Authorized Signature	
	Mr. Jamie Milner Vice President Pipeline Integrity & Safety Enbridge Gas Distribution Mar. 2/12 Date

Enbridge RCAM Allocation Trend - 2007 To 2013

	Services / Direct Charges	2007 (As Approved by the OEB in EB-2006-0034)	2008 (As Approved by Enbridge under the ISA)	2009 (As Approved by Enbridge under the ISA)	2010 (As Approved by Enbridge under the ISA)	2011 (As Approved by Enbridge under the ISA)	2012 (As Approved by Enbridge under the ISA*)	2013 (As Proposed by Enbridge for Rate Recovery*)
Primary Services	2. Audit & Accounting Advice	$ 86,095	$ 80,559	$ 123,457	$ 176,276	$ 202,937	$ 91,270	$ 93,278
	3. Board of Directors Support	$ 511,270	$ 548,758	$ 524,382	$ 653,787	$ 512,237	$ 769,368	$ 785,892
	4. Business & Economic Financial Analysis	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	5. Business Development	$ 652,513	$ 648,678	$ 442,656	$ 440,041	$ 533,671	$ 736,918	$ 753,039
	6. Capital Market Financing & Access	$ 681,246	$ 704,394	$ 680,419	$ 857,868	$ 986,346	$ 1,020,173	$ 1,042,564
	7. Cash Management & Banking	$ 222,036	$ 228,425	$ 268,955	$ 346,810	$ 388,868	$ 481,073	$ 491,656
	8. Consolidation and Planning System Technical Support (Khalix)	$ 375,868	$ 411,470	$ 424,221	$ 492,550	$ 606,411	$ 245,089	$ 249,486
	9. Corporate Compliance	$ 99,725	$ 79,694	$ 103,385	$ 129,802	$ 134,323	$ 197,202	$ 201,540
	10. Industry Relations and Corporate Social Responsibility (CSR)	$ 245,307	$ 184,961	$ 310,317	$ 399,487	$ 465,205	$ 384,365	$ 392,741
	11. Emerging Energy Technology Research	$ 146,966	$ 73,533	$ 55,901	$ 74,371	$ 47,593	$ -	$ -
	12. Employee Development	$ 255,425	$ 326,279	$ 547,313	$ 803,140	$ 1,200,754	$ 1,260,568	$ 1,288,299
	13. Enterprise IT Program Management	$ 149,002	$ 198,557	$ 183,664	$ 413,230	$ 389,669	$ 868,494	$ 887,579
	14. Enterprise IT Strategy Planning & Management	$ 550,749	$ 534,684	$ 446,745	$ 594,422	$ 467,282	$ 624,115	$ 637,845
	15. Expense System Management & Technical Support (Oracle iExpense)	$ 119,526	$ 131,407	$ 147,714	$ 167,015	$ 239,394	$ 95,490	$ 97,384
	16. External Audit Coordination	$ 43,174	$ 42,501	$ 56,582	$ 76,248	$ 63,299	$ 103,399	$ 105,673
	18. Financial and Project Accounting System Technical Support (Oracle)	$ 320,766	$ 244,535	$ 256,641	$ 254,570	$ 261,570	$ 352,161	$ 358,097
	21. Gas Supply, Storage, and Transportation Strategy	$ 571,267	$ 525,390	$ 390,843	$ 231,134	$ -	$ -	$ -
	22. Government Relations	$ 119,234	$ 165,187	$ 47,715	$ 120,509	$ 34,848	$ 44,917	$ 45,895
	23. HRIS Management and Technical Support	$ 689,995	$ 802,393	$ 742,447	$ 1,545,942	$ 2,169,992	$ 3,009,273	$ 3,075,443
	24. Human Resource Advice	$ 101,190	$ 92,772	$ 168,134	$ 271,938	$ 354,073	$ 201,779	$ 206,184
	26. Insurance Claims Support, Strategy and Management (Combined)	$ 87,617	$ 75,291	$ 83,820	$ 127,227	$ 126,457	$ 108,240	$ 109,912
	28. Investor Services	$ 994,024	$ 843,304	$ 585,153	$ 685,330	$ 811,451	$ 883,837	$ 903,044
	29. Employee and Labour Relations (Combined)	$ 253,530	$ 299,985	$ 348,384	$ 458,995	$ 552,430	$ 478,201	$ 488,722
	30. Legal Advice	$ 303,414	$ 365,223	$ 433,306	$ 749,045	$ 572,710	$ 514,396	$ 525,600
	32. Planning, Management & Execution of Internal Audits	$ 82,338	$ 87,693	$ 187,727	$ 228,607	$ 185,494	$ 191,528	$ 195,741
	33. Rate Regulated Entity Support	$ 328,451	$ 225,379	$ 97,621	$ 128,419	$ 147,295	$ 253,904	$ 259,490
	34. Records and Information Management	$ 456,875	$ 623,795	$ 494,550	$ 298,336	$ 304,392	$ 538,352	$ 550,195
	36. Risk Assessment and Management	$ 541,913	$ 623,959	$ 686,348	$ 882,571	$ 1,062,095	$ 878,461	$ 897,681
	37. Strategic Planning	$ 167,834	$ 183,816	$ 160,673	$ 194,768	$ 253,879	$ 327,890	$ 335,020
	38. Supply Chain Management	$ 19,504	$ 9,394	$ 21,249	$ 24,088	$ 30,414	$ 39,706	$ 40,580
	40. Tax Reporting & Planning	$ 10,196	$ 13,238	$ 14,512	$ 21,630	$ 24,894	$ 55,308	$ 56,525
	41. Total Compensation and Benefits	$ 865,843	$ 887,721	$ 850,234	$ 1,313,100	$ 1,410,246	$ 1,781,809	$ 1,820,969
	43. Portal Suite Operations & Technical Support	$ 259,283	$ 263,057	$ 236,449	$ 156,062	$ 172,685	$ 330,881	$ 338,160
	Total Service Charges	**$ 10,312,177**	**$ 10,526,035**	**$ 10,121,518**	**$ 13,317,317**	**$ 14,712,914**	**$ 16,868,167**	**$ 17,234,234**
General Expenses & Direct Charges	Direct EFS Charge (Credit)	$ (453,946)	$ (461,261)	$ (213,789)	$ (1,174,981)	$ (1,150,894)	$ (2,314,784)	$ (2,314,784)
	Directors Fees & Expenses	$ 501,718	$ 475,364	$ 426,433	$ 517,905	$ 545,235	$ 744,819	$ 761,205
	Depreciation - Risk Management System	$ 24,512	$ 72,919	$ 74,436	$ 13,827	$ 68,965	$ 64,951	$ 64,951
	Insurance Premiums	$ 4,905,300	$ 4,096,200	$ 4,571,600	$ 5,179,873	$ 4,338,678	$ 8,483,868	$ 8,483,868
	Audit Fees	$ 808,955	$ 1,044,041	$ 1,248,118	$ 1,125,631	$ 1,369,832	$ -	$ -
	Enbridge Stock Based Compensation Charge	$ 1,663,249	$ 3,122,013	$ 4,262,039	$ 4,842,397	$ 6,413,231	$ 7,549,229	$ 7,715,312
	Total Direct Charges	**$ 7,449,788**	**$ 8,349,277**	**$ 10,368,836**	**$ 10,504,652**	**$ 11,585,047**	**$ 14,528,083**	**$ 14,710,552**
	Return on Invested Capital	**$ 300,553**	**$ 198,909**	**$ 625,604**	**$ 443,159**	**$ 369,543**	**$ 368,896**	**$ 357,703**
	Total Enbridge Allocation	**$ 18,062,517**	**$ 19,074,221**	**$ 21,115,958**	**$ 24,265,127**	**$ 26,667,504**	**$ 31,765,146**	**$ 32,302,489**

* Prior to proposed adjustment by MNP per MNP Final Report dated May 17, 2012, entitled: "Independent Evaluation of the 2013 Regulatory Cost Allocation Methodology Results"

Effective 2012, please note the following:

1. Two primary services have been combined, Insurance Claims Support and Insurance Strategy and Management.
2. Audit Fees **(Direct Charge) have** been removed, as **they are** no longer accounted for under **the** RCAM.

DEFERRAL AND VARIANCE ACCOUNTS

Clearance of Deferral and Variance Accounts

1. As indicated within Enbridge Gas Distribution Inc.'s ("Enbridge" or the "Company") EB-2007-0615 Incentive Regulation ("IR") proceeding, for the period relating to fiscal years 2008 through 2012, the Company is required to file an application for the proposed review and clearance of deferral and variance accounts as soon as feasibly possible following finalization of the preceding fiscal years financial results. In line with that requirement, within the Company's 2011 Earnings Sharing Mechanism and Deferral and Variance Accounts Request for Clearance application (planned for the spring of 2012), Enbridge may request the review and clearance of the following previously approved but outstanding accounts.

Gas related DA's and VA's:

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

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

5. 2011 Carbon Dioxide Offset Credits DA ("CDOCDA"),
6. 2011 Class Action Suit DA ("CASDA"),
7. 2011 Deferred Rebate Account ("DRA"),
8. 2011 Electric Program Earnings Sharing DA ("EPESDA"),
9. 2011 Gas Distribution Access Rule Costs DA ("GDARCDA")
10. 2011 Manufactured Gas Plant DA ("MGPDA"),
11. 2011 Municipal Permit Fees DA ("MPFDA"),
12. 2011 Ontario Hearing Costs VA ("OHCVA"),

Witnesses: K. Culbert
R. Small

13. 2011 Unbundled Rate Implementation Cost DA (“URICDA”),
14. 2011 Unbundled Rates Customer Migration VA (“URCMVA”),
15. 2011 Average Use True-Up VA (“AUTUVA”),
16. 2011 Tax Rate and Rule Change VA (“TRRCVA”),
17. 2011 Earnings Sharing Mechanism DA (ESMDA”),
18. 2011 International Financial Reporting Standards Transition Costs DA (“IFRSTCDA”),
19. 2011 Open Bill Service DA (“OBSDA”),
20. 2011 Open Bill Access VA (“OBAVA”),
21. 2011 Open Bill Revenue VA (“OBRVA”),
22. 2011 Ex-Franchise Third Party Billing Services DA (“EFTPBSDA”),
23. 2009 Mean Daily Volume Mechanism Deferral Account (“MDVMDA”),
24. 2010 Mean Daily Volume Mechanism Deferral Account (“MDVMDA”),
25. 2011 Mean Daily Volume Mechanism Deferral Account (“MDVMDA”), and

DSM related DA’s and VA’s:

26. 2010 Demand Side Management VA (“DSMVA”),
27. 2011 Demand Side Management VA (“DSMVA”),
28. 2010 Lost Revenue Adjustment Mechanism (“LRAM”),
29. 2011 Lost Revenue Adjustment Mechanism (“LRAM”),
30. 2010 Shared Saving Mechanism VA (“SSMVA”),
31. 2011 Shared Saving Mechanism VA (“SSMVA”.

2. For 2012, the final year of Enbridge’s current IR model, Enbridge will file an application in the spring of 2013 for the review and proposed clearance of any remaining un-cleared deferral and variance accounts. The accounts to be reviewed within that proposal will consist of any accounts listed above which as at that time have not received approval for clearance and any eventual 2012 related accounts

Witnesses: K. Culbert
R. Small

which have been approved to be established. Within its 2012 rate proceeding EB-2011-0277, Enbridge has requested the approval of the following list of previously approved and additionally requested for approval deferral and variance accounts, most of which had been approved in prior years.

Gas related DA's and VA's

1. 2012 Purchased Gas VA ("PGVA"),
2. 2012 Transactional Services DA ("TSDA"),
3. 2012 Unaccounted for Gas VA ("UAFVA"),
4. 2012 Storage and Transportation DA ("S&TDA"), and

Non-Gas related DA's and VA's

5. 2012 Carbon Dioxide Offset Credits DA ("CDOCDA"),
6. 2012 Class Action Suit DA ("CASDA"),
7. 2012 Deferred Rebate Account ("DRA"),
8. 2012 Electric Program Earnings Sharing DA ("EPESDA"),
9. 2012 Gas Distribution Access Rule Costs DA ("GDARCDA"),
10. 2012 Manufactured Gas Plant DA ("MGPDA"),
11. 2012 Municipal Permit Fees DA ("MPFDA"),
12. 2012 Ontario Hearing Costs VA ("OHCVA"),
13. 2012 Unbundled Rate Implementation Cost DA ("URICDA"),
14. 2012 Unbundled Rates Customer Migration VA ("URCMVA"),
15. 2012 Average Use True-Up VA ("AUTUVA"),
16. 2012 Tax Rate and Rule Change VA ("TRRCVA)
17. 2012 Earnings Sharing Mechanism DA ("ESMDA"),
18. 2012 Open Bill Service DA ("OBSDA"),
19. 2012 Open Bill Access VA ("OBAVA")
20. 2012 Open Bill Revenue VA ("OBRVA")

21. 2012 Ex-Franchise Third Party Billing Services DA (“EFTPBSDA”),
22. 2012 Mean Daily Volume Mechanism DA (“MDVMDA”), /u
23. 2012 Transition Impact of Accounting Changes Deferral Account (“TIACDA”)

DSM related DA’s and VA’s

24. 2012 Demand Side Management VA (“DSMVA”),
25. 2012 Lost Revenue Adjustment Mechanism (“LRAM”),
26. 2012 Demand Side Management Incentive DA (“DSMIDA”).

Test Year – 2013

3. The Company proposes to establish the following group of gas supply related deferral and variance accounts in the 2013 Test Year.

2013 Purchased Gas Variance Account (“PGVA”),
2013 Design Day Criteria Transportation Deferral Account (“DDCTDA”),
2013 Transactional Services Deferral Account (“TSDA”),
2013 Unaccounted for Gas Variance Account (“UAFVA”),
2013 Storage and Transportation Deferral Account (“S&TDA”)

4. The Company proposes to establish the following non-gas supply related deferral and variance accounts in the 2013 Test Year:

2013 Deferred Rebate Account (“DRA”),
2013 Customer Care CIS Rate Smoothing Deferral Account (“CCCISRSDA”),
2013 Average Use True Up Variance Account (“AUTUVA”),
2013 Carbon Dioxide Offset Credits Deferral Account (“CDOCDA”),

Witnesses: K. Culbert
R. Small

2013 Manufactured Gas Plant Deferral Account (“MGPDA”),
2013 Gas Distribution Access Rule Costs Deferral Account (“GDARCDA”),
2013 Ontario Hearing Costs Variance Account (“OHCVA”),
2013 Electric Program Earnings Sharing Deferral Account (“EPESDA”),
2013 Open Bill Revenue Variance Account (“OBRVA”),
2013 Ex-Franchise Third Party Billing Services Deferral Account (“EFTPBSDA”),
2013 Transition Impact of Accounting Changes Deferral Account (“TIACDA”),
2013 Demand-Side Management Variance Account (“DSMVA”),
2013 Lost Revenue Adjustment Mechanism Variance Account (“LRAM”),
2013 Demand Side Management Incentive Deferral Account (“DSMIDA”)

Descriptions of Accounts

2013 Purchased Gas Variance Account ("2013 PGVA")

5. The purpose of the 2013 PGVA is to record the effect of price variances between actual 2013 gas purchase prices and forecast prices which underpin the revenue rates to be charged in 2013. Without this deferral account, the ratepayers and the Company are exposed to the risk of purchased gas price variances, which could unduly penalize or benefit one party at the benefit or expense of the other. Lower than forecast gas purchase prices would result in an over recovery from the customers and higher prices would result in an under recovery to the Company. This deferral account ensures that such effects are eliminated.

Methodology

6. The actual unit cost is determined by dividing the total commodity and transportation costs (less the demand charges related to unutilized TransCanada PipeLine Limited (“TCPL”) firm service transportation capacity, if any) plus any other costs associated with emerging gas pricing mechanisms incurred in the month by

the actual volumes purchased in the month. The rate differential between the PGVA reference price and the actual unit cost of the purchases, multiplied by the actual volumes purchased, is recorded in the PGVA monthly.

7. The fixed cost component of the TCPL firm service transportation costs (i.e., Transportation Demand Charge) is included in the determination of the reference price. However, any demand charges relating to unutilized longhaul TCPL ("FT") transportation capacity, either forecast or actual, are excluded. This treatment of forecast and actual longhaul TCPL Transportation Demand Charges for unutilized transportation capacity is consistent with the Board's concerns that these amounts be excluded from the PGVA.

8. Since all transportation costs on volumes purchased by the Company related to forecast utilized capacity are included in the determination of the PGVA reference price, any changes in the TCPL tolls will be recorded in the PGVA. Any toll changes related to the cost of forecast unutilized longhaul TCPL transportation capacity will also be recorded in the PGVA. The inclusion of changes in TCPL tolls in the PGVA is consistent with past practice.

9. Since the transportation tolls for the Alliance and Vector pipelines that were used in the determination of the PGVA reference price were based on an estimate, any variation between the actual transportation costs (including associated fuel costs) and the estimated transportation costs will be recorded in the PGVA.

10. Since transportation costs related to the transport of Western Canada Bundled T-service volumes are not included in the derivation of the PGVA reference price, changes in TCPL tolls will be recorded in the PGVA as a separate adjustment.

11. For the period January 1, 2013 to December 31, 2013 expenditures related to TCPL's Storage Transportation Services, including balancing fees related to TCPL's Limited Balancing Agreement, will be recorded in the 2013 PGVA. The 2013 PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.

12. The PGVA will record adjustments related to transactional services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the 2013 PGVA and 2013 TSDA for purposes of deferral account dispositions.

13. In addition, the 2013 PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.

14. The 2013 PGVA will also record an inventory valuation adjustment every time a recalculated “Utility Price” or PGVA Reference Price comes into effect at the beginning of a quarter. The adjustment consists of the storage inventory valuation adjustment necessary to price actual opening inventory volumes at a rate equal to the Board approved quarterly PGVA reference price.

15. The 2013 PGVA will also record any refund/collection associated with Board approved Gas Cost Adjustment Riders.

16. The Company will record, at the time a Banked Gas Account Balance is purchased from a customer, the difference in the amount payable to the customer and the amount included in the PGVA (Transportation Service Rider A). This amount would be credited to a sub-account of the PGVA. In the event the Company incurs unforecast UDC costs as a result of having to purchase Banked Gas Account Balances then the amount in such sub-account will be used to offset corresponding UDC costs. All amounts remaining in this sub-account, after offsetting these UDC costs, will be rolled up into the PGVA.

17. The commodity sale price on the disposition of Banked Gas Account Balances, the incentive sale price, is set at 120% of an average Empress price over the 12 months of the contractual year. Any amount in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt, will be included in the PGVA.

18. Simple interest is to be calculated on the opening monthly balance of the 2013 PGVA at the approved short-term debt interest rate.

<u>2013 Design Day Criteria Transportation Deferral Account ("2013 DDCTDA")</u>

19. The Company has prepared its 2013 Gas Cost budget assuming the current Design Day Criteria and based upon the volumetric forecast for 2013, the Company has forecast that it will incur $8.3 million in unutilized transportation which is captured within the 2013 Gas Cost forecast.

20. The Company is proposing a new Design Day Criteria. The purpose of the proposed 2013 DDCTDA is to record the actual cost consequences of unutilized transportation capacity contracted by the Company to meet increased requirements resulting from the proposed Design Day Criteria.

21. Should the Board accept the new methodology, the Company believes the only way to satisfy the increased Peak Day requirements at this time will be through the acquisition of incremental TCPL STFT capacity for January 2013 to March 2013. As discussed at Exhibit D1, Tab 2, Schedule 1, paragraph 13, the Company has forecast that based upon current tolls, this will have an impact of $66.2 million in gas costs. However, the Company is proposing to not include the cost consequences of that unutilized capacity in rates at this time.

22. Instead the Company requests that a deferral account be established to capture the costs associated with any incremental unutilized capacity. This will allow for the opportunity that if a less expensive firm pipeline alternative(s) become available and if the Company still incurs unutilized costs, then only the those incremental costs actually incurred will be recorded in the account and be eligible for collection. The hope is that less expensive options will arise which can be pursed.

23. Simple interest is to be calculated on the opening monthly balance of the 2013 DDCTDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing

<u>2013 Transactional Services Deferral Account ("2013 TSDA")</u>

24. The Company's proposes to follow the structure, sharing mechanism, and all other terms and conditions of the Transactional Services deferral account as set out in evidence at Exhibit C1, Tab 4, Schedule 1.

25. Simple interest is to be calculated on the opening monthly balance of the 2013 TSDA at the approved short-term debt interest rate. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2013 Unaccounted for Gas Variance Account ("2013 UAFVA")</u>

26. The purpose of the 2013 UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of Unaccounted for Gas ("UAF") and the Board approved UAF volumetric forecast. The Company proposes that the 2013 UAF volume variance calculation measure the 2013 actual UAF against the UAF volume forecast.

27. The gas costs associated with the UAF variance will be calculated at the end of Calendar 2013 based on the estimated 2013 volumetric variance between the 2013 Board approved level and the estimate of the actual UAF. An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF and actual UAF.

28. The UAF annual variance would then be allocated on a monthly basis in proportion to actual sales and the related cost would be calculated using the monthly PGVA reference price. Carrying costs for the UAFVA will be calculated on the allocated monthly balances at the approved short-term debt interest rate. The balance of the

UAFVA, together with the carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2013 Storage and Transportation Deferral Account ("2013 S&TDA")

29. The purpose of the 2013 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the company. It will also be used to record variances between the forecast Storage and Transportation rebate programs and the final rebates received by the company.

30. The 2013 S&TDA will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, this account will be used to record amounts related to deferral account dispositions received or invoiced from Storage and Transportation suppliers.

31. The 2013 S&TDA will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

32. Simple interest is to be calculated on the opening monthly balance of the 2013 S&TDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2013 Deferred Rebate Account ("2013 DRA")

33. The Company proposes to establish a 2013 DRA to record any amounts payable to, or receivable from, customers of the Company as a result of the clearing of deferral

accounts authorized by the Board which remain outstanding due to the Company's inability to locate such customers. The account will also include amounts arising from differences between actual and forecast volumes used for the purpose of clearing deferral account balances.

34. Simple interest is to be calculated on the opening monthly balance of this account at the approved short-term debt interest rate. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2013 Customer Care / CIS Rate Smoothing Deferral Account ("2013 CCCISRSDA")</u>

35. The Company proposes to establish a 2013 CCCISRSDA to capture the difference between the forecast customer care and CIS costs versus the amount to be collected in revenues as approved by the Board in the EB-2011-0226 CIS Customer Care Settlement Agreement and proceeding. The amount to be debited or credited to the deferral account for 2013 and for each subsequent year through 2018, will be calculated by multiplying the difference in cost per customer and smoothed costs per customer, times the updated customer forecast for the year. The balances in the account will not be cleared during the 2013 through 2018 period. The balance will build up during the years 2013 to 2015 when the cost per customer exceeds the smoothed cost per customer being collected in rates, and then the balance will be drawn down during the years 2016 to 2018 when the cost per customer is lower than the smoothed cost per customer being collected in rates. After 2018, any remaining balance in the account it is to be cleared along with the clearance of other 2018 deferral and variance accounts.

36. Interest is to be calculated on the balance of this account at a fixed annual rate of 1.47%, and will not change during the period the deferral account is allowed to

continue through 2018. The interest carrying charges will be disposed of annually at the same time of clearance of all other deferral and variance accounts.

2013 Average Use True Up Variance Account ("2013 AUTUVA")

37. The purpose of the 2013 AUTUVA is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6 and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism ("LRAM"), extended by the average use volume variance per customer and the number of customers.

38. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2013 Carbon Dioxide Offset Credits Deferral Account ("2013 CDOCDA")

39. The purpose of the 2011 CDOCDA is to record amounts which represent proceeds resulting from the sale of or other dealings in earned carbon dioxide offset credits. This deferral account was originally approved by the Board in its Natural Gas Generic DSM proceeding, EB-2006-0021.

40. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2013 Manufactured Gas Plant Deferral Account (“2013 MGPDA”)</u>

41. The Company is proposing to establish a 2013 MGPDA in order to capture all costs incurred in managing and resolving issues related to the Company’s Manufactured Gas Plant (“MGP”) legacy operations. Amounts recorded in the 2010 MGPDA will also be transferred to the 2011 MGPDA. Costs charged to the account could include, but are not limited to:

- Responding to all enquiries, demands and court actions relating to former MGP sites;
- All oral and written communications with existing and former third party liability and property insurers of the Company;
- Conducting all necessary historical research and reviews to facilitate the Company’s responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;
- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former MGP operations and providing advice regarding the appropriate steps to remediate/contain/monitor such contamination, if any;
- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company’s existing and former third party liability and property insurers; and
- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

42. The MGPDA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

43. Simple interest is to be calculated on the opening monthly balance of the 2013 MGPDA at the Board approved short-term interest rate. The balance of this account together with carrying charges will be disposed of in a manner designated by the Board in a future rate hearing.

2013 Gas Distribution Access Rule Cost Deferral Account (“GDARCDA”)

44. The purpose of the 2013 GDARCDA is to record all incremental unbudgeted capital and operating costs associated with the development, implementation, and operation of the Gas Distribution Access Rule. Such costs would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required, operating costs in relation to the establishment of contractual agreements and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR.

45. Simple interest is to be calculated on the opening monthly balance of this account at the approved short-term debt interest rate. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

2013 Ontario Hearing Costs Variance Account (“2013 OHCVA”)

46. The Company proposes to establish the 2013 OHCVA in order to record the variance between actual 2013 rate proceeding and other proceedings, activities and

related expenses and the budgeted level of $7.3 million as shown in evidence at Exhibit D1, Tab 13, Schedule 1.

47. Simple interest will be calculated on the opening monthly balance of the account at the approved short-term debt interest rate. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

<u>2013 Electric Program Earnings Sharing Deferral Account (“2013 EPESDA”)</u>

48. The Company proposes to establish a 2013 EPESDA under the same parameters as agreed to, established and approved in the EB-2011-0008, 2010 Earnings Sharing Mechanism proceeding. The account will be used to track and account for the ratepayers 50% share of net revenue generated by DSM services provided under contract to the OPA and electric LDCs.

49. Simple interest will be calculated on the opening monthly balance of the account at the approved short-term debt interest rate. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

<u>2013 Open Bill Revenue Variance Account (“ 2013 OBRVA”)</u>

50. The purpose of the 2013 OBRVA is to track and record the ratepayer share of net revenue for Open Bill Services. The account allows for net annual revenue amounts in excess of $7.389 million to be shared 50/50 with ratepayers, and allows for a credit to Enbridge in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009.

51. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2013 Ex-Franchise Third Party Billing Services DA (“ 2013 EFTPBSDA”)

52. The purpose of the 2013 EFTPBSDA is to record and track the ratepayer share of revenues generated from third party billing services provided to ex-franchise parties net of incremental costs associated with the services. The net revenue is to be shared on a 50/50 basis with ratepayers. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009.

53. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2013 Transition Impact of Accounting Changes DA (“2013 TIACDA”)

54. The Company proposes to establish a 2013 TIACDA to accommodate the impact, if any, of the Board’s decision with respect to the Company’s proposal for any future required treatment of the impacts of the required transition away from Canadian Generally Accepted Accounting Principles.

55. The company is not proposing that interest will be calculated on the balance of the account.

Witnesses: K. Culbert
R. Small

DSM Related Variance Accounts (3)

2013 Demand Side Management Variance Account ("2013 DSMVA"),

2013 Lost Revenue Adjustment Mechanism Variance Account ("2013 LRAM"),

2013 Demand Side Management Incentive Deferral Account ("2013 DSMIDA")

56. With one exception in respect of the 2013 DSMVA, the Company proposes to establish the same group of DSM related deferral and variance accounts as finally approved by the Board in Enbridge's eventual 2012, EB-2011-0277 rate proceeding and its EB-2011-0295 DSM related proceeding.

57. Given the fact that the Board has not approved a DSM Budget for 2012 and 2013, the Company has used for ratemaking purposes in this proceeding the 2012 base DSM Budget from the DSM Guidelines of $28.1 million and increased this amount by the estimated GDP-IPI rate of 1.73% which produces a forecast DSM budget for 2013 of $28.6 million. As there is a reasonable probability that this 2013 forecast budget of $28.6 million will change, the Company proposes that any increase (or decrease) be recorded in the 2013 DSMVA for eventual clearance. The recording of any variance from the 2013 DSM forecast budget in the DSMVA would however not impact the Company's ability to otherwise utilize the DSMVA as contemplated by the DSM Guidelines. In other words, the Company would remain capable of spending an additional 15% above the Board approved 2013 DSM budget and any debit or credit arising out of a variance to the 2013 forecast DSM Budget of $28.6 million used in this proceeding would not otherwise affect the Company's use of the DSMVA.

58. Simple interest is to be calculated on the opening monthly balance of these accounts at the approved short-term debt interest rate. The balance of these

accounts, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Criteria for Establishment of Deferral and Variance Accounts

59. The criteria adopted by the Company in determining when to come forward for a rate order or an accounting order request for a deferral or variance account includes the following considerations:

- the materiality of the amount at risk (revenue or expense);
- protection of the ratepayer or the shareholder from benefitting at the expense of the other party related to a variance in the forecast amount;
- the level of uncertainty associated with a forecast of the amount at risk; and
- the aspect of control - are the underlying circumstances beyond the Company's ability to control.

2013 HUMAN RESOURCES DEPARTMENT O&M EXPENSES

Mandate and Responsibilities

1. The Human Resources Department is comprised of two functions – Human Resources and Facilities Services. The Facilities Services function in its entirety was realigned to report to Human Resources effective January 2010.

2. Human Resources is responsible for ensuring that Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") is able to attract, develop and retain talented people to meet the needs of the business, ensuring operational excellence.

3. Facilities Services manages all Enbridge facilities, currently 21 properties (nine owned and twelve leased) totaling 668,600 square feet. The department is responsible for the planning and utilization of buildings to provide a safe and healthy work environment for all building occupants while optimizing the use of and efficiency of all facilities ensuring adherence to building codes and by-laws, fire codes, and environmental regulations.

Services and Activities

4. The Human Resources department consists of various functions, such as, Business Support, Compensation, Organizational Effectiveness, and Employee Services. Services provided include recruitment and selection, development of training programs, compensation studies, performance and succession management. Human Resources ensures a competitive, motivating, and healthy work environment for all employees.

5. Facilities Services conducts strategic property planning, acquisition and disposal of properties, lease administration, asset management, and internal project

management of all reconfiguration, relocation, renovation and construction projects. The daily operation of buildings and grounds entails the maintenance and upgrade of building systems, energy management initiatives, premise security, life safety systems, business continuity planning, mail and delivery, and cleaning services.

6. Over the last several years, the Company analyzed its use of several facilities and determined that it would be appropriate to consolidate various operations and training activities for several locations into a new multi-purpose facility. This project will meet the joint needs of the technical training group and Central Region East Operations and will involve the consolidation of the following existing facilities into one site: Markham Construction and Warehouse, Richmond Hill Operations Depot, VPC Engineering Materials Evaluation Center, and Technical Training in Pickering and Richmond Hill. The site will include a one-acre "Streetscape" where employees will be trained on real-life simulations in a safe and controlled environment. This will provide comprehensive, practical and theoretical training on critical tools and equipment. Construction is underway and the facility's opening is scheduled for 2012. With the consolidation of these activities, it is the Company's expectation that savings will be realized in 2013, with a reduction in leasing cost, travel time, and overall organizational efficiency gains as a result of the consolidation.

2013 Budget

Table 1

Human Resources Budget for 2013

Line No.	Particulars ($ 000's)	2013 Budget
		$
1	Salaries and Wages	5,746
2	Benefits	30,452
3	Pension	27,704
4	Outside Services	6,307
5	Rents and Leases	3,663
6	Costs Charged to Affiliates	(64)
7	Other	7,743
8	Total	81,551
9	Full-Time Equivalent ("FTE")	72

7. The 2013 Budget for Human Resources is $81.6 million as illustrated in Table 1.

8. Total FTE's forecast for the 2013 budget is 72. The Human Resources and Facilities Services group consists of Management, Supervisory and Unionized employees who provide services to the rest of the Company. Salaries and Wages for these FTE's is $5.7 million of the total O&M budget.

9. Benefits are a major component of the 2013 Budget, at $30.5 million. See Employee Expenses and Workforce Demographics at Exhibit D1, Tab 3, Schedule 2 for additional information on benefits.

10. Pension costs are another major component of the 2013 Budget. It is forecasted at $27.7 million.

11. Outside Services are budgeted at $6.3 million. This budget includes facilities contractor costs associated with the daily operation of buildings and building utility costs.

12. Rents and Leases for 2013 are budgeted at $3.7 million.

13. Costs Charged to Affiliates include charges to Enbridge Gas New Brunswick and Gazifère for employee records maintenance, benefit, pension and payroll administration. These costs are budgeted at ($0.1) million.

14. Other expenses include consulting fees, employee training and development, materials and supplies, travel, severances and membership fees. They are budgeted at $7.7 million.

Variance Explanations – 2013 Budget vs 2012 Estimate

Table 2

Human Resources Department
Operating and Maintenance Expense
2013 Budget versus 2012 Estimate

Line No.	Particulars ($ 000's)	2013 Budget	2012 Estimate	2013 Budget vs. 2012 Estimate
		$	$	$
1	Salaries and Wages	5,746	5,612	134
2	Benefits	30,452	25,941	4,511
3	Pension	27,704	20,557	7,147
4	Outside Services	6,307	5,808	499
5	Costs Charged to Affiliates	(64)	(63)	(1)
6	Other	7,743	5,695	2,048
7	Total Gross Operating and Maintenance Expense	81,551	66,937	14,614
8	FTE	72	73	(1)

15. The 2013 Budget increases by $14.6 million from the 2012 Estimate.

16. The 2013 salaries and wages budget increases by $0.1 million from the 2012 Estimate due to salary increases of 3.3%, offset by a reduction of one temporary FTE.

17. Benefits increase by $4.5 million. The majority of the increase is due to a change in accounting practices from Canadian GAAP to U.S. Generally Accepted Accounting principles (“USGAAP”) which amounts to $2.9 million. The remainder of the increase is driven by: (1) an increase of $0.4 million for Canada Pension Plan, Employment Insurance, and Employers Health Tax due to a higher salary base; (2) an increase of $0.7 million for employee benefits due to an increase in FTEs; (3) higher prescription costs, dental fees; (4) the impact of higher employee utilization.

18. Pension expenses have increased $7.1 million from the 2012 Estimate. This increase is due to the plans expected deficit position at the end of 2011 requiring contributions. These contributions represent current employee service costs as well as contributions starting in 2013 required to bring the plan from a deficit position to a surplus position. The 2012 pension expenses represent expenses under a cash basis whereas 2013 pension expense represents pension expense under an accrual basis of accounting under USGAAP. The increase, however, has no bearing on the fact that two different accounting methodologies are being used. Regardless of whether you use a cash or accrual basis of expense, Enbridge will incur an increase from 2012 to 2013. Indeed, the USGAAP accrual methodology provides for a smaller increase over 2012 compared to a cash basis. For a full analysis of cash versus accrual basis of pension expense, please refer to EB-2011-0354, at Exhibit A1, Tab 6, Schedule 2.

19. Outside Services increase by $0.5 million from the 2012 Estimate due to higher contractor costs, inflationary increases for building utility costs and a higher level of relocation expenses for planned building moves in 2013.

20. Rents and Leases increase by $0.3 million from the 2012 Estimate due to additional office space requirements to accommodate employee growth.

21. Costs Charged to Affiliates remain virtually unchanged.

22. Other expenses increase by $2.0 million from 2012 Estimate primarily due to severance costs and additional compensation related cost due to a greater emphasis placed upon performance management.

Variance Explanations – 2012 Estimate vs 2011 Historic

Table 3

Human Resources Department
Operating and Maintenance Expense
2012 Estimate versus 2011 Historic

Line No.	Particulars ($ 000's)	2012 Estimate	2011 Historic	2012 Estimate vs. 2011 Historic
		$	$	$
1	Salaries and Wages	5,612	5,098	514
2	Benefits	25,941	23,193	2,748
3	Pension	20,557	3,224	17,333
4	Outside Services	5,808	5,592	216
5	Rents and Leases	3,387	2,683	704
6	Costs Charged to Affiliates	(63)	(218)	155
7	Other	5,695	5,229	466
8	Total Gross Operating and Maintenance Expense	66,937	44,801	22,136
9	FTE	73	68	5

23. The 2012 Estimate will see an overall increase of $22.1 million over the 2011 Historic Year.

24. Salaries and wages increase by $0.5 million due to general wage increases for inflation, and an increase of five FTE's. The additional FTE's were in the area of (1) Change Management which is a new service provided to the Company which is offset by previous external consultants at a higher cost, (2) Human Resources Consultants required to support the increased demand for services in the area of recruitment, performance management, etc. (3) temporary Employee Services Representative to support additional workload in the area of pension, benefits and payroll, (4) plant maintenance support for the new Technical Training facility.

25. Benefits increased by $2.7 million driven by (1) an increase of $0.4 million for Canada Pension Plan, Employment Insurance, and Employer Health Tax due to a higher salary base; (2) an increase of $1.9 million for employee benefits due to an increase in FTE; (3) higher prescription costs and, dental fees, and (4) the impact of higher employee utilization.

26. Pension costs increase by $17.3 million from 2011 Historical to 2012 Estimate. This increase is primarily due to the funded status of the plan going from a surplus position to a deficit position where the plan surplus or deficit is the net position when comparing the fair-value of the plan assets against the actuarial assessment of the plan obligations as at a given date. An excess of plan assets over plan obligations results in a surplus, while the reverse results in a deficit. Due to the pension plan expected to be in a deficit position, Enbridge is required to fund the pension plan for an amount that represents annual employee current service costs. As such the increase from 2011 is primarily employee current service costs as a

result of pension regulations requiring plan sponsors to fund pension plans should the plan be in a deficit position. Please refer to EB-2011-0277, at Exhibit B, Tab 2, Schedule 6 for details on the funded status, filing requirements, and the impact to the Company.

27. Outside Services increase by $0.2 million due to higher facilities contactor costs and increases in utility costs due to inflation.

28. Rents and Leases are $0.7 million higher in 2012 due to planned acquisition of additional office space to accommodate requirements at the head office facility.

29. Costs Charged to Affiliates decrease from $0.2 million in 2011 Historic to $0.1 million in 2012. In 2011, some of the backfills for employees who were seconded to an HR project team was charged back to the project.

30. Other expenses increase by $0.5 million due to compensation related costs aimed at a stronger focus on performance management.

<u>Updated Evidence</u>

31. 2011 Actual Benefits expense was $24,263 million compared to the 2011 Historic of $23,193 filed. The $1.1 million increase was a result of increased medical and dental claims by employees. /u

Witness: S. Trozzi

2013 NON-DEPARTMENTAL O&M EXPENSES

Mandate and Responsibilities

1. Within Enbridge Gas Distribition Inc's ("Enbridge" or the "Company") Operation and Maintenance ("O&M") Budget there are certain costs that are not department specific and as such are not included within the costs of any one department. The purpose of this evidence is to provide details of these non-departmental costs.

2. The non-department specific costs are comprised of two major components: 1) executive management team ("EMT") salaries and their administrative support costs, consulting fees, corporate memberships and other administration and general costs and 2) short term incentive program ("STIP").

Services and Activities

3. All Enbridge EMT members and their administrative support costs are contained within the executive salaries and expenses budget. This senior team has overall responsibility for the day to day operations of the Company.

4. This budget also includes corporate memberships paid by the Company to industry associations such as the Canadian Gas Association, the American Gas Association, and the annual licensing fee to the Technical Standards & Safety Authority ("TSSA"); for the distribution of natural gas.

5. The STIP is the variable pay component of compensation for all permanent employees. It is performance-driven and is intended to focus employees on achieving and exceeding specific corporate, business unit, departmental and/or individual goals that are determined on an annual basis.

6. STIP is a pay-at-risk program in that payment is tied to achievement of previously-established results, and must be re-earned each year. Variable pay target levels are established to ensure market competitiveness and are benchmarked against the Company's comparator group of companies. Target levels vary by pay grade within the organization with executive and management employees having more pay at risk than front-line employees to reflect their greater ability to directly influence performance outcomes. STIP for unionized employees is governed by the Collective Agreement.

7. Enbridge tracks the achievement of financial and operational results through the use of "scorecards" at both the Company and departmental levels. Efficiency and productivity is facilitated by having each employee's performance linked to the achievement of specific metrics that reflect their contribution to the successful execution of the business strategy.

8. Adding measurable and clear metrics to the Company and department scorecards, aligns the business objectives of the Company with the activities of the employee. Employees as a result understand their contribution to the business and the role that they play in the achievement of business results. Many metrics are dependent upon improved productivity and performance. Examples of such metrics are; (1) Net Earnings, (2) Public Safety & Reliability, (3) Employee Safety, (4) Customer Satisfaction, (4) Best Employer Status.

9. The STIP 2013 Budget, 2012 Estimate, 2011 Historic and 2010, 2009, 2008, 2007 Actual is outlined below. There are three key factors that are measured for STIP calculation purposes; (1) Enbridge Inc. Company Multiplier is measured by Corporate Return on Equity ("ROE"), (2) Enbridge Multiplier is measured on the business unit scorecard results, (3) Individual Performance (non unionized

employees) is reflected by an employee's overall performance rating assigned by the manager. The Company Performance (ROE or "Company Multiplier") and the Business Unit Performance ("Enbridge Multiplier") targets and actual are outlined below. For budgeting purposes, the Company uses a multiplier of one. Where the actual multiplier used is greater than one, it means that all or some combination of the productivity or safety improvement, customer satisfaction, or other scorecard target has been achieved.

	2013 Budget $000	2012 Estimate $000	2011 Historic $000	2010 Actual $000	2009 Actual $000	2008 Actual $000	2007 Actual $000
Short Term Incentive Program	$20,257	$19,428	$22,272	$18,881	$25,303	$19,109	$20,086
Enbridge Inc. Multiplier	1.00	1.00	1.30	1.50	2.00	2.00	2.00
Enbridge Multiplier	1.00	1.00	1.02	1.45	1.68	1.48	1.49

2013 Budget

Table 1

Non-Department Budget for 2013

Line No.	Particulars ($000's)	2013 Budget
		$
1	Salaries and Wages	3,526
2	Short Term Incentive Program	20,257
3	Costs Charged to Affiliates	(60)
4	Other	2,478
5	Eliminations of Donations	(10)
6	Total	26,191
7	FTE	16

10. The 2013 Budget for Non-Department specific costs is $26.2 million as illustrated in Table 1 above.

11. The largest single component is the "STIP", with a budget of $20.3 million. The calculation of the STIP is based on an increase in the salary base of 3.3% from 2012, and both the "Corporate multiplier" and "Enbridge multiplier" is estimated at 1.00.

12. Executive salaries and wages to be incurred during the normal course of business are budgeted at $3.5 million.

13. Compensation levels are competitively based on upon market conditions that reflect

the local labour market in which the Company competes for talent. Enbridge has a defined comparator group of companies comprised of large organizations, see Mercer Compensation Study, Exhibit D2, Tab 3, Schedule 1. The pay philosophy that Enbridge utilizes is to target total cash compensation at the 50th percentile (plus or minus 10%) of the market. The Mercer report indicates that Enbridge is currently slightly below (-2%) market P50 for total cash compensation for Senior Management. The Mercer report also indicates that Senior Management is slightly above (2%) market P50 on total compensation.

14. Costs Charged to Affiliates compensate the Company for its executives spending time on affiliate work, including attendance at affiliate board meetings for St. Lawrence Gas, Gazifere Inc., Niagara Gas Transmission and Enbridge Gas New Brunswick. $0.1 million is budgeted to be charged to affiliates in 2013.

15. Other expenses, budgeted at $2.5 million, include material and supplies, employee training and development expenses, outside services, consulting fees, travel and other business expenses and corporate and trade membership fees.

Variance Explanation 2013 Budget vs 2012 Estimate

Table 2

Non-Departmental
Operating and Maintenance Expense
2013 Budget versus 2012 Estimate

Line No.	Particulars ($ 000's)	Budget 2013	Estimate 2012	2013 Test Year vs. 2012 Estimate
		$	$	$
1	Salaries and Wages	3,526	3,429	97
2	Short Term Incentive Program	20,257	19,428	829
3	Costs Charged to Affiliates	(60)	(60)	(0)
4	Customer Care Service Charges (including CIS)	0	1,020	(1,020)
5	Other	2,478	2,359	119
6	Eliminations of Donations	(10)	(10)	(0)
7	Total Gross Operating and Maintenance Expense	26,191	26,166	25
8	FTE	16	16	(0)

16. The 2013 Budget is $26.2 million, which is an immaterial increase from the 2012 Estimate of $26.2 million for non-departmental costs.

17. Executive salaries and wages increase by $0.1 million. This is the result of the 3.3% salary increase in base salaries from the 2012 Estimate.

18. The STIP budget for 2013 Budget is $0.8 million higher than the 2012 Estimate. The assumptions used for determining the 2013 STIP payout budget remain unchanged from 2012. The driver of the STIP increase is due to the higher salary base in 2013.

19. The Customer Care Services Charges (including Customer Information System ("CIS")) of $1.0 million in 2012 belong to Customer Care department, but is booked in the non-departmental budget. These charges do not apply in 2013 as the five year amortization period for the CIS vendor selection costs ended in 2012.

20. Other expenses increase by $0.1 million to account for increases in travel and business expenses driven by inflationary pressures.

Variance Explanation 2012 Estimate vs 2011 Historic

Table 3

Non-Departmental
Operating and Maintenance Expense
2012 Estimate versus 2011 Historic

Line No.	Particulars ($ 000's)	Estimate 2012	Historic 2011	2012 Estimate vs. 2011 Historic
		$	$	$
1	Salaries and Wages	3,429	3,265	164
2	Short Term Incentive Program	19,428	22,272	(2,844)
3	Costs Charged to Affiliates	(60)	(43)	(17)
4	Customer Care Service Charges (including CIS)	1,020	1,020	(0)
5	Other	2,359	1,526	833
6	Eliminations of Donations	(10)	(10)	(0)
7	Total Gross Operating and Maintenance Expense	26,166	28,030	(1,864)
8	FTE	16	16	0

21. The 2012 Estimate for Non-Departmental specific costs is $26.2 million. This is a decrease of $1.9 million from the Historic 2011 total.

22. Salaries and wages in the Non-Departmental 2012 Estimate increases from the 2011 Historic figures by $0.2 million due to base salary wage increases and promotions. The 2012 Estimate and 2013 Budget both use a 3.3% increase in salaries.

23. The largest single component of the 2012 Estimate is the STIP at $19.4 million which is estimated to be $2.8 million lower than 2011 Historic year figure. The 2012 Corporate performance multiplier is estimated at 1.00 compared to 2011 Historic multiplier of 1.30.

24. Other Expenses increase by $0.8 million due to the reversal of compensation related costs in 2011.

Updated Evidence-STIP

25. 2011 Actual Short Term Incentives paid was $26.0 million compared to the 2011 Historic of $22.3 million, an increase of $3.7 million. The increase in STIP payout is the result of improved financial performance in comparison to original estimates and higher levels of employee performance recognized at year end.

UPDATED REGULATORY ADJUSTMENTS AND ELIMINATIONS – CAM ELIMINATION TO ADJUST FOR RCAM

1. The Company has eliminated the difference between CAM and RCAM elsewhere in the updated O&M evidence as follows:

	2013	2012	2011 Actual
CAM*	$47.2M	$46.8M	$41.8M
RCAM**	$32.1M	$31.6M	$26.7M
Difference	$15.1M	$15.2M	$15.1M

*The 2012 and 2013 CAM amounts represent the original values

** The 2012 and 2013 RCAM values reflect the MNP proposed RCAM amounts for 2012 and 2013 per MNP's Final Report dated May 17, 2012 which the Company has adopted.

2. Please also refer to Exhibit D1, Tab 4, Schedule 2 and Exhibit D2, Tab 1, Schedule 1

Witnesses: K. Culbert
J. Jozsa
B. Yuzwa

UNACCOUNTED FOR GAS STUDY

1. The purpose of this evidence is to present an unaccounted for gas ("UAF") study in accordance with the settlement agreement from the EB-2011-0008 proceeding (Exhibit N1, Tab 1, Schedule 1). The agreement states on page 14: *"Enbridge agrees that, as part of the evidence in support of its 2013 application, it will file a study addressing what steps gas distribution utilities are taking in regard to measuring, forecasting, controlling the variability and managing the amount of unaccounted for gas volumes, and to compare what Enbridge is doing in respect of these issues relative to other gas distribution utilities."*

2. This UAF study is the first one conducted by Enbridge Gas Disitrbution Inc. ("Enbridge" or the "Company"). In preparing this study, discussion meetings with the Company's subject matter experts and benchmarking comparisons were conducted to address the requirements mentioned above.

3. The measurement and UAF management sections discuss the programs and processes that are are in place to enhance the measurement accuracy, to monitor the third party transmission pipelines' custody transfer metering accuracy, to strengthen the metering process and to manage the UAF by undertaking initiatives to reduce leaks in the pipe, third party damages to the pipe, release to the atmosphere during normal maintenance operations or theft. A comparison of these activities and UAF forecasting methodologies with other gas utilities concludes this study.

4. In summary, the Company either already embraces or has work in progress related to sixteen out of twenty steps identified from the industry benchmarking best practices in measuring, controlling the variability and managing the UAF. In some cases, the Company goes beyond the best practices and undertakes additional

steps to minimize the measurement variations when possible. The remaining four practices that the Company has not implemented relate to using energy instead of volumetric units in billing end-use customers. The Company is currently not aware of other gas utilities within Ontario that have initiated this practice. As evidenced in Chart 1 on page 3, the Company's UAF percentage has been consistently lower than the industry averages of 172 utilities within North America. The Company's regression model performs better than the known objective forecasting methodologies in terms of forecast accuracy.

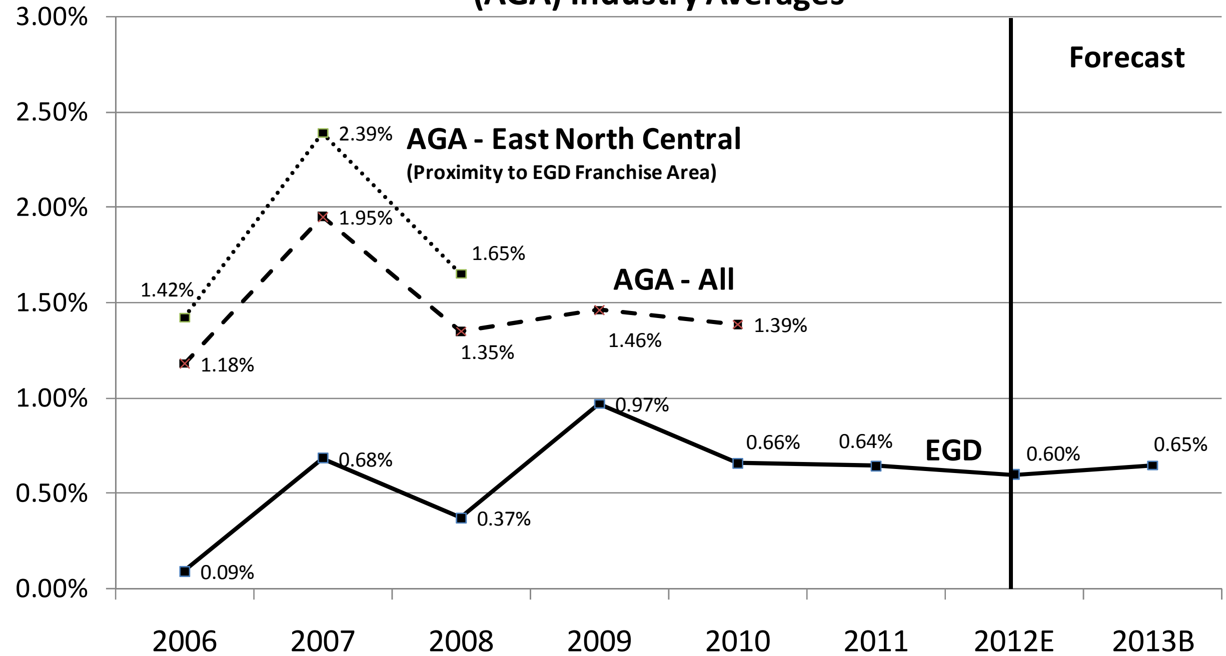
5. UAF is the difference between the gas delivered into the distribution system being billed by the third party transmission pipelines (i.e. TransCanada Pipelines Limited ("TCPL"), and Union Gas Limited ("Union")) and the gas measured out of the utility system. In other words, UAF represents the difference between metered gas deliveries (or sendout) and metered consumption of the Company's 1.96 million customers.

6. For the purpose of comparing the Company's UAF with other gas distribution utilities, it is necessary to establish the UAF level expressed as percentage of total gas sendout. Chart 1 on the next page illustrates the Company's UAF percentage has been consistently lower than the American Gas Association ("AGA") industry averages of 172 utilities in North America.[1]

7. In recognition of the fact that UAF is volatile (Chart 1) and the fluctuating commodity costs associated with the UAF are beyond the control of utilities, currently there are 102 utilities in United States and Canada that have UAF true up mechanisms to enable them to recover the costs of unaccounted for gas that are not recovered from customers in the utilities' base cases.[2]

[1] American Gas Association. (2010). Lost and Unaccounted For Gas. Financial and Operational Information Series.
[2] American Gas Association. (2009). Lost and Unaccounted For Gas Cost Recovery Mechanisms. Natural Gas Rate Round-Up.

Chart 1: UAF % Comparison with American Gas Association (AGA) Industry Averages*



*Note: American Gas Association. (2010). Lost and Unaccounted For Gas. Financial and Operational Information Series.

- The Company's percentage is based upon 12 months ending December 31 of the reporting year.
- The AGA's percentages are based upon 12 months ending June 30 of the reporting year.
- AGA's 2009 and 2010 actual percentages are based on preliminary simple averages of raw data obtained from the 2011 Best Practices Benchmarking Data Report.

/u

8. UAF arises from meter differences, operational or external factors such as line leakage, unmetered uses and third party damage. It is known that gases are more difficult to measure than other concrete items, as measured volumes are highly affected by temperature and pressure. Measurement Canada also observes that gas meter measurement is “a pretty complicated mechanism”.[3] An article from the AGA likewise stated that the primary cause of UAF is meter uncertainty.[4]

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[3] http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm03961.html
[4] American Gas Association. (2009). Lost and Unaccounted For Gas Cost Recovery Mechanisms. Natural Gas Rate Round-Up

Measurement and Variability Control

9. Accurate measurement of gas volume is a function of the meter and the factors used to adjust the meter read of compensating temperature, pressure, atmospheric pressure or elevation[5], and gas quality or heating value variations. These factors are applied to the meter read to compensate for the effect of the meter's operational environment on the volume of gas.

10. The Company's large volume customer meters are already adjusted for temperature and pressure variations. All mass market meters purchased after 1998 are already corrected for temperature as required by Measurement Canada. Meters that are not temperature corrected must be installed inside.

11. Prior to billing the metered consumption is adjusted for atmospheric pressure as prescribed by Measurement Canada. Enbridge began using the pressure factors (Rider F in the Rate Handbook) beginning in 2001 for meters that do not correct for atmospheric pressure in order to ensure appropriate billing regardless of elevation. Currently, the metered consumption is not adjusted for gas quality or heating value variation as the standard unit of natural gas volume measurement and consumer billing is cubic meters, a volumetric measure.

12. Billed volumes of 1.96 million customers are based upon the Company's metered volumes. All meters must be inspected and certified to Measurement Canada standards and comply with Canada's Electricity and Gas Inspection Act[6] and associated Regulations[7] before being installed in the field. The Company calibrates and maintains measurement equipment with the objective of keeping all

[5] Atmospheric pressure can affect meter reading. The higher the elevation is, the lower the atmospheric pressure. Natural gas expands at lower atmospheric pressures and contracts at higher. In other words, it expands on mountains and shrinks in valleys.
[6] http://laws-lois.justice.gc.ca/eng/acts/E-4/index.html
[7] http://laws-lois.justice.gc.ca/eng/regulations/SOR-86-131/index.html

metering variations within Measurement Canada's mandated tolerances. Accordingly, all new meters installed in the field must be within the tolerance level of +/- 1.0% and all in- service installed meters must be maintained within the tolerance level of +/- 3.0%. Measurement Canada audits the Company's metering performance annually. In addition, the Company has meter accuracy policy in place and examples are explained in the next section.

13. Additional steps are undertaken to strengthen the metering process and some examples are listed below.
    - All the large volume meter stations are inspected annually.
    - Mass market customer meters are inspected in accordance with the Measurement Canada sampling standard.[8]
    - All of the new or re-worked meters have to be calibrated within the tolerance level of +/-0.3% which is even lower than the tolerance level of +/-1% mentioned in the previous paragraph as prescribed by Measurement Canada.
    - Meter accuracy is monitored on a regular basis. If a meter's accuracy has deteriorated, the meter is replaced.
    - A doubtful meter process is conducted by the Company's Customer Care group. When the meter reader identifies that a meter is not registering, they send a code from their mobile device to the Work Management Centre to send a fitter out to validate and replace the meter if necessary.
    - There is software within the meter readers' mobile device which validates whether meter readings are within certain tolerance level or parameters.
    - Further validation of readings is performed by the billing system to verify the reasonableness of readings. If readings are outside the tolerance level, an incident is generated for the Company's back-office to confirm these readings manually.

[8] http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm04356.html

- Sampled billings are verified on a daily basis using test procedures to validate metered consumption against bill charges.

14. Billing estimation and variations between meter reading billing cycle and calendar month that are associated with operational uncertainties such as changes to number of people per household, number or type of gas furnace, changes to customer usage behavior, number of billing days per billing cycle and, move-in and move-out of customers, etc. were not included in the study because these kinds of variations typically cancel each other out over a twelve-month period. Accordingly, their impacts on the UAF are just temporary in nature.

15. Gas sendout volumes are defined as the total gas volumes determined from TCPL and Union Gas billed information based upon their respective measurement information at the various points of interconnection with the Company's distribution system. The measurement volume received from TCPL and Union is based upon their meter (custody transfer meter) information. Their meters are also inspected and certified to the Measurement Canada standard.

16. The Company has installed check meters that are operated in accordance with Canada's Electricity and Gas inspection Act and Regulations for each city gate station to monitor the accuracy of these custody transfer meters on a daily basis and whether they are within the +/- 2% tolerance permitted by applicable agreement. If the difference between custody transfer and check meter information falls outside this +/- 2% tolerance, the Company will investigate the variance and seek a resolution with TCPL and Union accordingly. The Company also reconciles, on a monthly basis, the custody transfer meter information against the many gas supply commodity, transportation and storage invoices.

17. TCPL and Union invoice quantities in in energy units (gigajoules (GJ)) in contrast to the volumetric units (cubic metres, (m^3)) used by the Company to bill its 1.96 million customers. Accordingly, invoiced amounts from TCPL and Union have to be converted to cubic meters based upon the corresponding quality or heating value of the gas. Depending upon the quality of gas acquired, the heating values can fluctuate on a daily basis and vary amongst different locations or sources.[9,10]

18. Chart 1 on page 3 illustrates that the Company's UAF% has ranged from 0.1 to 1%, on average, 0.6%, from 2006 to 2011. This percentage has been consistently /u lower than the AGA industry averages of 172 utilities in North America. The Company has always been complying with Measurement Canada meter verification tolerance limit of +/- 1.0 % and dispute tolerance of +/- 3.0% for 1.96 million gas meters . Given that the Company's own meter accuracy policy requires all of the new or re-worked meters have to be calibrated within the tolerance level of +/-0.3% which is even lower than the tolerance level of +/-1% as prescribed by Measurement Canada, any additional UAF% can be potentially attributed to the +/- 2% meter variations of the TCPL and Union and other system gas escape factors that are discussed in the UAF management section below.

19. The Company continues to control the measurement variability as described in detail above and to manage the amount of UAF as further discussed below in the management section. To the degree that the measurement variability is sourced from the third party transmission companies and is within the industry tolerance level of +/-2%, the year over year variability or fluctuation would be beyond the Company's control.

[9] www.transcanada.com/.../docs/.../Gas_Quality_Specifications_Fact_Sheet.pdf
[10] http://www.uniongas.com/aboutus/aboutng/composition.asp

20. All metered volumes are subject to the calibration and accuracy of the individual meters as well as environmental factors, such as heating value, which affect the gas volume measurement. In other words, the instruments cannot be calibrated to an absolute zero.[11] The nature of operations of the gas distribution business will always result in certain routine measurement variances due to metering differences, quality of the gas, and atmospheric pressure impacts.

21. To summarize measurement and variability considerations, the Company is in compliance with Measurement Canada requirements and benchmarks its metering process with respect to measurement variability with other gas utilities. The Company is one of the Measurement Canada accredited service providers. Accredited organizations are those organizations that have been delegated authority to inspect devices on behalf of Measurement Canada pursuant to the Electricity and Gas inspection Act. Enbridge is also one of the few organizations can provide more than two inspection type services.[12] Moreover, the Company set its meter accuracy policy to have lower tolerance level than the standard prescribed by Measurement Canada for new and re-worked meters. Finally, the Company uses its check meters to monitor the accuracy of custody transfer meters maintained by third party transmission pipelines to ensure metering variations are within the industry standard of +/-2% tolerance.

UAF Management

22. This section discusses the UAF that results from factors other than measurement variation. As gas flows through the pipe network, gas may be lost due to: leaks in the pipe; accidental damage to the pipe; release to the atmosphere during normal maintenance operations or; theft.

[11] http://www.feddevontario.gc.ca/eic/site/mc-mc.nsf/eng/lm00041.html.
[12] http://corporations.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00527.html#Enbridgee

23. First, leaks in the pipe are usually caused by factors such as corrosion, construction defects, material failure and third party excavators. The Company has multiple ongoing initiatives to address these issues. Initiatives include leak survey programs, leak detection and repair management system and, cast iron and bare steel mains replacement program. The program to replace cast iron and bare steel mains is scheduled to be completed by 2012 and is expected to reduce the leak or break failure rate of the Company's gas mains.

24. Second, the greatest risk facing the Company's pipelines is damage caused by third party excavators. Over the last 10 years, the number of recorded damages per 1,000 locates has decreased by 70%. Total damages have decreased by 36% during this same timeframe, and locate error rates have decreased by 15%. Over this same period, locate requests have increased 112%. Even though the activity level has increased significantly as reflected by the increase in locate requests damages and locator errors have dropped sharply due to an increased focus on education and training for both excavators and locators.

25. The Company continuously seeks new ways to protect pipeline assets through innovative strategies and incorporating industry best practices. Initiatives include: completing a marketing research study on effectiveness of consumer communications programs; training presentations for locators and excavators; efforts to move forward on a single national phone number (811); legislation to establish a mandatory One Call system in Ontario, and improved tracer wire technology in order to provide additional protection to assets.

26. Third, during normal maintenance procedures or emergency shutdowns, gas is released to the atmosphere inevitably. Referred to as "blowdown", this venting of natural gas from a pressurized system occurs due to maintenance or emergency procedures such as taking a system offline for repair or emergency pressure

release. The Company has undertaken various steps to prevent, recapture, reduce, or redirect vented emissions from a pressurized system containing gas. Examples of these steps are: flaring; compression; pressure reduction; volume reduction and; blowdown avoidance. For other safety and integrity projects, please refer to Exhibit B1, Tab 2, Schedule 4.

27. Lastly, with respect to the theft or unmetered use, the Company has a number of initiatives already in place. For instance, a report is run on a monthly basis to monitor large volume customer meters that are installed but not turned on; and meter readers are trained to identify signs of gas bypass or potential theft. In addition, a new program was implemented in October 2011 to provide meter readers with a financial reward every time they identify gas bypass or potential theft.

28. As a further comment on the Company's commitment to managing UAF Enbridge has been participating in the CSA Canadian GHG Challenge Registry and voluntarily reporting its fugitive emissions since the mid-1990s.[13] While broader in scope than simply managing fugitive emissions the submitted action plans has been evaluated to either gold or silver status since 2002.[14] The Company's 2011 plan is currently in development. These action plans and recommendations will be integrated with the Company's operations to minimize the system gas escape and green house gas emissions from a system-wide perspective.

29. Overall, as these factors impact the distribution system's safety and reliability which is the Company's top priority, the Company has been, on an ongoing basis, undertaking multiple initiatives and steps to manage these factors. While it is difficult to quantify the impact of these factors on UAF, the Company does not believe the impact is material.

[13] Fugitive emissions are emissions, other than venting and flaring from above and below-ground pipeline networks and facilities that are unintentional and include third party system damages.
[14] http://www.ghgregistries.ca/challenge/cha_entity_e.cfm?No=52

Comparison with Other Gas Distribution Utilities – Measurement and Management

30. Table 2 below compares the best practices benchmarking results from other gas distribution utilities with respect to steps taken to measure, control the variability and manage UAF.

Table 2: Comparison with Other Gas Distribution Utilities: Measurement and Management

AGA Roundtable Results Best Practices Benchmarking[15]	Enbridge Gas Distribution Practices[16]
1. Incentive to accurately account for UAF ▪ Report UAF in dollars on the annual report.	✓ The volumetric variations were reported on the annual information form. Readers can calculate the dollars from the pricing information within the MD&A report. ✓✓ The Company has been voluntarily reporting and managing fugitive emissions since the mid-1990s. The submitted action plan has been evaluated to either gold or silver status since 2002. ✓✓ A customer meter field measurement program has been undertaken to obtain better emission factors from fugitive equipment leaks on natural gas metering systems.
Billed volume accuracy ▪ Utilize SOx guidelines. ▪ Establish practices that meet Sarbanes-Oxley requirements.	✓ The Company has utilized SOx guidelines and has established multiple SOx controls. These controls are tested and validated by external auditors annually as part of the SOx certification process to ensure the volumes billed to customers are based upon the metered numbers input to the billing application. ✓ Sampled billings are verified on a daily basis using test procedures to validate metered consumption against bill charges.

[15] American Gas Association. (2004). Lost and Unaccounted for Gas Roundtable Results. *Best Practices Benchmarking*. This benchmarking study is the latest and the most comprehensive study of North American available from either internet sites or large Gas Association membership directories or paper records.
[16] ✓✓ denotes the Company goes beyond the best practice
✓ denotes the Company adopts the same practice
× represents the Company currently has not endorsed the same practice
○ corresponds to the Company is either currently in progress in embracing the same practices or partially accepting the practices

AGA Roundtable Results Best Practices Benchmarking[15]	Enbridge Gas Distribution Practices[16]
	✓ There is another validation level within the billing system to validate if the readings are reasonable. If the readings are outside the tolerance level, an incident is generated for the back-office to work on these readings manually.
2. Accuracy of Suppliers' custody meter reads. ▪ Install a check meter at city gate stations. ▪ Develop a real time handoff to Storage Operational Data Acquisition (SCADA) of Meter Data. ▪ Perform a weekly review of the daily data.	✓ The Company has installed check meters that are operated in accordance with Canada's Electricity and Gas Inspection Act and Regulations for each city gate station. ✓ The check meter data is obtained from the SCADA data system automatically at a 24/7 monitoring centre based in Edmonton. ✓✓ The data is monitored on a daily basis.
3. Establish a Meter Test program by meter class. ▪ Ongoing verification that pressure factors and meter accuracy meet standards.	✓ All meters must be inspected and certified to the Measurement Canada standards before being installed in the field. ✓✓ Each year, the Company also conducts sample testing on accuracy of measuring devices. Based on a sample of 424 meters, the average accuracy for the period 2007-2010 is about 0.44% which is lower than the Measurement Canada prescribed standard for meter accuracy of +/-3%. ✓✓ All of the large volume meter stations are inspected annually. ✓✓ Meter accuracy is monitored on a regular basis. If meters have deteriorated, they are replaced. ✓✓ A doubtful meter process is conducted by Customer Care group. When the meter reader identifies that a meter is not registering, a code is sent from the handheld to Work Management Centre to send a fitter out to validate and replace the meter if necessary. ✓✓ There is software within the meter readers' handhelds to validate whether the readings are within certain tolerance level or parameters. ✓✓The Company's meter accuracy policy has lower tolerance levels than the standard prescribed by Measurement Canada for new and re-worked meters.

AGA Roundtable Results Best Practices Benchmarking[15]	Enbridge Gas Distribution Practices[16]
▪ Monitor new elevated pressure meter installations on a monthly basis.	✗ New elevated pressure meter installations are not monitored on a monthly basis as processes are already in place to ensure the Company's meter performance is in accordance with Measurement Canada standards. Atmospheric pressure factors from Rider F of the rate handbook are then applied to the metered volumes automatically based upon the geographic region of the meter.
4. Accuracy of large volume meters at low flow periods. ▪ Install dual meter runs – one low volume and one high volume.	○ Dual-run meters are only used for emergencies. For customers that have unique load, dual meter runs are installed, one large meter for high volume and one small meter for seasonal or low measurement.
5. Divide the system into energy (e.g. BTU, GJ, etc) zones for more accurate volume (DTH, m^3) calculations. ▪ Separate the system into energy zones. ▪ Determine the energy value for each zone. ▪ Automate the energy to volume relationship by customer for billing.	✗ Not warranted at this time. ✗ Same comment as above. ✗ Same comment as above.
6. Automatic calculation of the UAF. ▪ Develop appropriate programs to encompass or analyze all data including deliveries, inputs, receipts, billing, etc.	○The Company has already initiated multiple IT projects to automate the calculation of the UAF by storing gas deliveries, purchases, and receipts into a data warehouse application.
7. Proper measurement equipments are selected and installed for each meter or regulator application. ▪ Establish a measurement training program ▪ Establish measurement policies and procedures ▪ Create a standard table of compatible meter and regulator combinations	✓ Yes. ✓ Yes. ✓ Yes.
8. Establish a cross functional team to monitor and discuss the UAF on a monthly basis.	○There is a cross functional team to monitor and discuss the UAF on a quarterly basis. The monthly practice will be considered after the data warehouse application of automating UAF calculation is implemented.

AGA Roundtable Results Best Practices Benchmarking[15]	Enbridge Gas Distribution Practices[16]
9. Reduce theft of service.	
▪ Provide incentives for field staff to identify theft of gas.	✓ A report is run on a monthly basis to monitor large volume meters that are installed but not turned on. ✓ Meter readers are trained to identify signs of gas bypass or potential theft.
▪ Provide monetary reward to customers who report theft or unauthorized use.	✗ Not warranted at this time
▪ Develop a training program for field employees on identifying theft or unauthorized use.	✓ A new program was already implemented in October 2011 to provide meter readers with a financial reward every time they have identified gas bypass or potential theft.

31. In summary, the Company either already embraces or has work in progress related to sixteen out of twenty steps identified from the industry benchmarking best practices in measuring, controlling the variability and managing the UAF. In some cases, the Company goes beyond the best practices and undertakes additional steps to minimize the measurement variations when possible. The remaining four practices that the Company has not implemented relate to using energy instead of volumetric units in billing end-use customers. The Company is currently not aware of other gas utilities within Ontario that have initiated this practice.

Comparison with Other Gas Distribution Utilities – Forecast

32. Please refer to Exhibit D3, Tab 4, Schedule 1, for a detailed discussion of the steps undertaken by the Company in forecasting the amount of UAF. The UAF forecast is calculated using a regression model. The major driver variables in the model are active meter customers, and other qualitative variables of reflecting the size of the distribution system and structural changes. Table 1 of Exhibit D3, Tab 4, Schedule 1, illustrates that the Company's regression model continues to outperform other alternative regression model specifications by producing lower in-sample and out-of-sample forecast variations than the alternative ones.

33. Given that the best practices benchmarking forecast performance of the UAF forecasting methodologies are not publicly available, the Company has compiled its own summary of UAF forecasting practices in North America by posting questions to the Gas Forecasters Forum[17], contacting utilities directly and researching regulatory evidence filed by utilities.

34. Table 3 on the next page demonstrates that there are four utilities currently adopting five-year average forecasting methodology, one utility embracing the three-year weighted average forecasting methodology, and the balance use subjective judgment forecasting methodology. Therefore, the five-year average forecast methodology appears to be the predominant approach amongst these eight utilities. Excluding the subjective judgement UAF forecasting methodologies, five-year average and three-year weighted average, are examined by comparing their mean square errors with the Company's regression model approach over the historical period 2006-2011, and the results are set out in Table 4 on page 17.[18] /u

[17] http://www.southerngas.org/index.php/gas-supply-marketing/201.
[18] 2006 is the first year that the Company prepares the budget numbers on a calendar year basis.

Table 3: UAF Forecasting Methodologies and Performance Comparison of North American Gas Utilities

Gas Utilities	Number of Customers	UAF Forecasting Methodologies	UAF Forecasting Performance
American	4.3 millions	Subjective judgement: 3-year average or a 1-year average depending on which average is judged to be the best predictor of the future.	Do not formally track the accuracy of the forecasts
American	2.3 millions	5-year simple average	Do not formally track the accuracy of the forecasts
American	3.3 millions	Subjective judgement: 4-year average or other recent actual depending on which average is judged to be the best predictor of the future.	Do not formally track the accuracy of the forecasts
American	0.7 millions	5-year simple average	Negotiated Amount
American	2.1 millions	5-year simple average	Do not formally track the accuracy of the forecasts
Canadian	1.3 millions	3-year weighted average	Present both forecast and actual within regulatory filing. 2006-2011 MAE* = 53 $10^6 m^3$.
Canadian	0.2 millions	Subjective judgement: 8-year average	Do not formally track the accuracy of the forecasts
Canadian	0.9 millions	5-year simple average	Do not formally track the accuracy of the forecasts

35. Mean absolute error ("MAE")[19] is used to evaluate the forecast accuracy of various methodologies because the Company's unaccounted for gas variance account ("UAFVA") is measured as the variance between actual and forecast levels. According to this criterion, the best forecasting methodology provides the smallest deviation between actual and forecast and the direction of the deviation is neutral to all stakeholders. In Table 4 provided on the following page, the Company's regression model performs better than the other forecasting methodologies adopted in North American utilities according to the MAE criterion.

[19] The formula used to calculate the mean absolute error is: $MAE = \frac{1}{n}\sum_{t=1}^{n}\left|(a_t - f_t)\right|$ where n = the number of time periods, a= actual, f= forecast, t= time reference.

Table 4: Comparison of Forecast Performance - UAF Forecasting Methodologies

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
					Forecast vs Actual Variance		
Year	**Actual**	**The Company's Regression Model - In-Sample Forecast**	**3-Year Weighted Average**	**5-Year Average**	**The Company's Model vs Actual**	**3-Year Weighted Average vs Actual**	**5-Year Average vs Actual**
2006	10,274	46,636	12,728	19,742	36,362	2,454	9,468
2007	83,823	51,311	(65,967)	6,676	(32,512)	(149,790)	(77,147)
2008	44,424	55,691	67,498	21,584	11,267	23,074	(22,840)
2009	110,917	58,108	65,733	26,186	(52,809)	(45,185)	(84,731)
2010	72,104	62,183	89,070	52,851	(9,920)	16,967	(19,253)
2011	73,355	66,870	85,625	64,308	(6,485)	12,270	(9,047) /u
2012*	68,134		89,254	76,925			
2013*	73,092		71,267	73,787			
				Mean Absolute Error:	24,893	41,623	37,081

*denotes forecast numbers

36. In summary, the Company's regression model approach is the best performing methodology among other known forecasting methodologies used in North American utilities in terms of forecast accuracy. It provides the smallest deviation between actual and forecast volumes over the historical period. Developing a forecasting model is an on-going process. This model passes a battery of statistical tests and is valid given the current and historical information as described in Exhibit D3, Tab 4, Schedule 1. Consistent with the past practise, the model will be continuously evaluated, tested, and refined as new information becomes available.

Conclusion

37. As evidenced in Chart 1 on page 3 of this exhibit, the Company's UAF percentage has been consistently lower than the industry averages of 172 utilities within North America. The Company's regression model performs better than the known forecasting methodologies in terms of forecast accuracy. The Company either

Witness: I. Chan

already embraces or has work in progress related to sixteen out of twenty steps identified from the industry benchmarking best practices in measuring, controlling the variability and managing the UAF. In some cases, the Company goes beyond best practices and undertakes additional steps to minimize measurement variations when possible.

38. There are some factors beyond the Company's control, such as metering variations from third party transmission pipelines and metering technology. As measurement is a sophisticated but imperfect estimation process, the accuracy of all of the meter information can only be evaluated within the required percentage of tolerance instead of an absolute value. Therefore, some uncertainty always exists. Best practices can reduce but not eliminate uncertainty.

39. As always, the Company will continue to evaluate and invest in cost effective new technologies and processes to control variability and manage the amount of UAF for the factors that the Company can control or influence.

COST OF SERVICE
COMPARISON OF UTILITY COSTS AND EXPENSES
2013 BUDGET AND 2012 ESTIMATE

		Col. 1	Col. 2	Col. 3
Item No.		2013 Budget ($Millions)	2012 Estimate ($Millions)	2013 Budget Over/(Under) 2012 Estimate ($Millions)
1.1	Gas costs charged to operations	1,548.6	1,515.5	33.1
1.2	Operations and maintenance	426.1	402.2	23.9
1.3	Depreciation	302.3	291.6	10.7
1.4	Fixed financing costs	2.3	2.3	-
1.5	Debt redemption premium amortization	-	0.2	(0.2)
1.6	Company share of IR agreement tax savings	-	25.6	(25.6)
1.7	Municipal and other taxes	40.1	38.8	1.3
1.0	Total costs and expenses	2,319.4	2,276.2	43.2

Witnesses: S. Kancharla
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2013 BUDGET AND 2012 ESTIMATE

Item No.

1.1 Gas costs charged to operations - increase of $33.1million

The increase in gas costs charged to operations in the 2013 Budget is primarily due to general service customer growth and the continued migration from T-service to system gas, partially offset by a lower gas demand forecast resulting from a forecast of warmer weather and the continued decline in average use for general service customers. Please refer to Exhibit C1, Tab 3, Schedule 1, for the details of the gas volume budget.

1.2 Operation and maintenance - increase of $23.9 million

The increase in operation and maintenance costs in the 2013 Budget is primarily due to: an increase in salaries and benefits resulting from an increase in base salary and wages and an increase in staff levels, an increase in pension expense and Other Post Employment Benefits (“OPEB”) as a result of the required transition away from Canadian Generally Accepted Accounting Principles, an increase in regulatory proceeding costs, and higher bad debts.

A comparison of the 2013 Budget to the 2012 Estimate operation and maintenance costs is provided at Exhibit D1, Tab 3, Schedule 1.

1.3 Depreciation expense – increase of $10.7 million

The increase in depreciation expense is mainly due to higher depreciable property, plant & equipment resulting from the annual capital expenditures, partially offset by a decrease in the 2013 depreciation expense as a result of the implementation of the proposed depreciation rates starting 2013 as recommended by the depreciation study. The details of the depreciation study are provided at Exhibit D1, Tab 5, Schedule 1.

Witnesses: S. Kancharla
R. Lei

1.5 Debt redemption premium amortization – decrease of $0.2 million

The debt redemption premium will be fully amortized in 2012 and there is no outstanding balance in 2013 and onwards.

1.6 Company share of Incentive Regulation ("IR") agreement tax savings– decrease of $25.6 million

The decrease reflects no tax saving sharing in 2013 as changes in tax rates and rules which contributed to the approved tax savings sharing mechanism are now incorporated into the 2013 cost of service revenue requirement. The $25.6 million represents the impact of the shareholder portion of agreed tax savings on utility income in 2012 in accordance with the current IR settlement agreement.

1.7 Municipal and Other Taxes – Increase of $1.3 Million

The increase reflects the inflationary pressure on municipal tax rate, increased municipal taxes in growth for new mains and service connections, and higher current value assessment. The details of municipal taxes are provided at Exhibit D1, Tab 6, Schedule 1.

Updated Evidence

The 2013 Budget has been updated to reflect evidence updates that affect the 2013 Test Year since EB-2011-0354 was originally filed.

COST OF SERVICE
COMPARISON OF UTILITY COSTS AND EXPENSES
2013 BUDGET AND 2012 ESTIMATE

		Col. 1	Col. 2	Col. 3
Item No.		Updated 2013 Budget ($Millions)	2012 Estimate ($Millions)	2013 Budget Over/(Under) 2012 Estimate ($Millions)
1.1	Gas costs charged to operations	1,307.9	1,515.5	(207.6)
1.2	Operations and maintenance	438.1	402.2	35.9
1.3	Depreciation	300.8	291.6	9.2
1.4	Fixed financing costs	2.3	2.3	-
1.5	Debt redemption premium amortization	-	0.2	(0.2)
1.6	Company share of IR agreement tax savings	-	25.6	(25.6)
1.7	Municipal and other taxes	40.1	38.8	1.3
1.0	Total costs and expenses	2,089.2	2,276.2	(187.0)

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2013 Test Year

Line No.	Particulars ($ 000's)	Updated Budget 2013	Original Budget 2013	2013 Updated Over(Under) 2013 Budget
1.	Finance	$ 7,782	$ 7,782	$ -
2.	Risk Management	1,183	1,183	-
3.	Customer Care Service Charges	70,032	70,032	-
4.	Customer Care Internal Costs	12,876	12,876	-
5.	Provision for Uncollectibles	15,172	15,172	-
6.	Energy Supply, Storage Development, Regulatory	15,688	15,688	-
7.	Legal and Corporate Security	5,661	5,661	-
8.	Operations	64,784	64,784	-
9.	Information Technology	38,331	38,331	-
10.	Business Development & Customer Strategy (excluding DSM)	11,351	11,351	-
11.	Human Resources (excluding benefits and pensions)	23,396	23,396	-
12.	Benefits	30,452	30,452	-
13.	Pensions	37,300	27,704	9,596
14.	Pipeline Integrity & Safety	38,713	38,713	-
15.	Public and Government Affairs	14,624	14,624	-
16.	Non Departmental Expenses	26,091	26,191	(100)
17.	Corporate Allocations (including direct costs)	47,268	47,268	-
18.	Subtotal	460,704	451,208	9,496
19.	Capitalization (A&G)	(37,704)	(35,669)	(2,035)
20.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	423,000	415,539	7,460
21.	Demand Side Management Programs (DSM)	31,440	28,632	2,808
22.	Conservation Services	1,507	1,507	-
23.	Total Net Utility O&M Expense before Eliminations	455,947	445,679	10,268
24.	Regulatory Eliminations			
25.	To eliminate Corporate Cost Allocations above RCAM	(15,124)	(16,953)	1,829
26.	To eliminate Conservation Services and Overheads	(2,462)	(2,462)	-
27.	Incremental O&M Allocated to Unregulated Storage	(233)	-	(233)
28.	Total Eliminations	(17,820)	(19,415)	1,596
29.	Total Net Utility O&M Expense	$ 438,127	$ 426,144	$ 11,983

Notes:
1) Departmental O&M costs are net of capitalization, non-utility,and other utility adjustments.

Witness: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
2013 Budget Year vs. 2012 Estimate Year

Line No.	Particulars ($000's)	Updated Budget 2013 (a)	Estimate 2012 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$ 170,856	$ 160,672	$ 10,185	6.3%
2.	Benefits	30,452	25,941	4,512	17.4%
3.	Pension	37,300	20,557	16,743	81.4%
4.	Short Term Incentive Program	20,257	19,428	830	4.3%
5.	Employee Training and Development	4,137	4,041	96	2.4%
6.	Materials and Supplies	5,511	5,495	16	0.3%
7.	Outside Services	78,979	77,868	1,112	1.4%
8.	Regulatory Costs	7,343	5,843	1,500	25.7%
9.	Consulting	9,541	6,687	2,854	42.7%
10.	Repairs and Maintenance	1,961	1,946	15	0.8%
11.	Fleet	9,974	9,768	206	2.1%
12.	Rents and Leases	7,671	7,438	233	3.1%
13.	Telecommunications	3,668	3,619	49	1.4%
14.	Travel and Other Business Expenses	4,891	4,702	189	4.0%
15.	Memberships	3,384	3,158	226	7.1%
16.	Claims, Damages and Legal Fees	816	754	62	8.2%
17.	Customer Care Service Charges (including CIS)	89,422	90,436	(1,013)	-1.1%
18.	Interest on Security Deposits	2,716	1,933	783	40.5%
19.	Provision for Uncollectibles	15,172	13,700	1,472	10.7%
20.	Internal Allocations and Recoveries	(25,263)	(25,130)	(133)	0.5%
21.	Corporate Cost Allocations (including direct costs)	47,268	46,816	453	1.0%
22.	Other	7,151	5,879	1,272	21.6%
23.	Subtotal	533,209	491,549	41,660	8.5%
24.	Capitalization (A&G)	(37,704)	(31,404)	(6,300)	20.1%
25.	Capitalization	(69,159)	(65,273)	(3,886)	6.0%
26.	Non-Utility Allocations	(3,347)	(3,220)	(127)	3.9%
27.	Total Net Utility O&M Expense, excl. DSM, Conservation	422,999	391,652	31,347	8.0%
28.	Demand Side Management Programs (DSM)	31,440	28,100	3,340	11.9%
29.	Conservation Services	1,507	6,978	(5,471)	-78.4%
30.	Total Net Utility O&M Expense before Eliminations	455,946	426,729	29,217	6.8%
31.	Regulatory Eliminations				
32.	To eliminate Corporate Cost Allocations above RCAM	(15,124)	(16,610)	1,486	-8.9%
33.	To eliminate Conservation Services and Overheads	(2,462)	(7,919)	5,456	-68.9%
34.	Incremental O&M Allocated to Unregulated Storage	(233)	-	(233)	
35.	Total Eliminations	(17,819)	(24,529)	6,709	-27.4%
36.	Total Net Utility O&M Expense	$ 438,127	$ 402,200	$ 35,926	8.9%

Note:
The Salaries and Wages (Line 1) exclude the salaries and wages embedded in the following line items because they have their own discrete regulatory treatments: Customer care service charges (Line 17), DSM (Line 28), and Conservation services (Line 29).

Witness: S. Kancharla
R. Lei

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2013

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $\$/10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)	
	Western Canadian Supplies					
1.1	Alberta Production	0.0	0.0	0.000	0.000	
1.2	Western - @ Empress - TCPL	1,791,414.5	276,997.5	154.625	4.103	
1.3	Western - @ Nova - TCPL	938,105.2	149,842.3	159.729	4.238	
1.4	Western Buy/Sell - with Fuel	1,849.7	298.3	161.292	4.279	
1.5	Western - @ Alliance	954,694.8	157,893.1	165.386	4.388	
1.6	Less TCPL Fuel Requirement	(63,637.4)	0.0			
1.	Total Western Canadian Supplies	3,622,426.8	585,031.2	161.503	4.285	
2.	Peaking Supplies	37,998.7	11,076.7	291.502	7.734	
3.	Ontario Production	730.0	172.8	236.703	6.280	
4.	Chicago Supplies	1,832,109.7	331,530.0	180.955	4.801	
5.	Delivered Supplies	1,478,310.2	274,640.4	185.780	4.929	/c
6.	Total Supply Costs	6,971,575.4	1,202,451.1	172.479	4.576	/c
	Transportation Costs					/c
7.1	TCPL - FT - Demand		211,895.7			/c
7.2	- FT - Commodity	2,667,732.0	14,455.6	5.419	0.144	/c
7.3	- Parkway to CDA		3,238.4			
7.4	- STS - CDA		5,793.8			
7.5	- STS - EDA		4,687.0			
7.6	- Dawn to CDA		9,471.0			
7.7	- Dawn to EDA		22,582.0			
7.8	- Dawn to Iroquois		7,063.3			
7.9	Other Charges		0.0			
7.10	Nova Transmission		7,039.6			
7.11	Alliance Pipeline		42,584.4			
7.12	Vector Pipeline		24,661.5			
7.	Total Transportation Costs		353,472.3			
8.	Total Before PGVA Adjustment	6,971,575.4	1,555,923.4	223.181	5.921	
9.	PGVA Adjustment		(202,757.0)			
10.	Total Purchases & Receipt	6,971,575.4	1,353,166.4	194.098	5.150	

Witnesses: J. Sarnovsky
D. Small

Summary of Gas Cost to Operations
Year ended December 31, 2013

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	6,971,575.4	1,353,166.4	194.098	5.150
11.	Storage Fluctuation	(71,162.8)	(13,812.5)		
12.	Commodity Cost to Operations	6,900,412.6	1,339,353.9	194.098	
13.	Storage and Transportation Costs		116,047.2		
14.	Gas Cost to Operations	6,900,412.6	1,455,401.1	210.915	5.596
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		93,221.1		
17.	Forecasted Gas Costs	6,900,412.6	1,548,622.2	224.425	5.954

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2013

Item #		
1.	Sendout To Operations	6,900,412.6
2.	T-Service Volumes	4,348,993.3
3.	Total Sendout	11,249,405.9
4.1	Residential Sales	3,801,385.9
4.2	Commercial Sales	2,400,197.3
4.3	Industrial Sales	474,553.5
4.4	T-Service	4,309,552.0
4.5	Rate 200 T-Service (Gazifere)	38,849.3
4.6		123,435.7
4.7	Company Use	5,176.3
4.8	Unaccounted For (UAF)	71,404.0
4.9	Unbilled Forecast - Sales	496.3
4.10	Unbilled Forecast - T-Service	592.0
4.11	Lost and Unaccounted For (LUF)	23,763.6
4.	Total System Requirements	11,249,405.9

Witnesses: J. Sarnovsky
D. Small

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2013

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	1,937,345.1	218,823.1	112.950	2.997
1.3	Western - @ Nova - TCPL	938,105.2	112,398.0	119.814	3.179
1.4	Western Buy/Sell - with Fuel	1,849.7	225.9	122.138	3.241
1.5	Western - @ Alliance	954,694.8	119,568.5	125.243	3.323
1.6	Less TCPL Fuel Requirement	(67,288.8)	0.0		
1.	Total Western Canadian Supplies	3,764,706.0	451,015.5	119.801	3.179
2.	Peaking Supplies	37,998.7	9,406.9	247.560	6.568
3.	Ontario Production	730.0	144.4	197.809	5.248
4.	Chicago Supplies	1,832,109.7	253,812.3	138.536	3.676
5.	Delivered Supplies	1,471,212.5	208,488.0	141.712	3.760
6.	Total Supply Costs	7,106,756.9	922,867.1	129.858	3.445
	Transportation Costs				
7.1	TCPL - FT - Demand		223,152.3		
7.2	- FT - Commodity	2,810,011.1	15,226.6	5.419	0.144
7.3	- Parkway to CDA		3,238.4		
7.4	- STS - CDA		5,793.8		
7.5	- STS - EDA		4,687.0		
7.6	- Dawn to CDA		9,471.0		
7.7	- Dawn to EDA		22,582.0		
7.8	- Dawn to Iroquois		7,063.3		
7.9	Other Charges		0.0		
7.10	Nova Transmission		7,039.6		
7.11	Alliance Pipeline		42,819.4		
7.12	Vector Pipeline		24,970.4		
7.	Total Transportation Costs		366,043.7		
8.	Total Before PGVA Adjustment	7,106,756.9	1,288,910.9	181.364	4.812
9.	PGVA Adjustment		(170,080.8)		
10.	Total Purchases & Receipt	7,106,756.9	1,118,830.0	157.432	4.177

Witnesses: J. Sarnovsky
D. Small

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2013

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	7,106,756.9	1,118,830.0	157.432	4.177
11.	Storage Fluctuation	(53,333.2)	(8,396.3)		
12.	Commodity Cost to Operations	7,053,423.7	1,110,433.7	157.432	
13.	Storage and Transportation Costs		110,479.8		
14.	Gas Cost to Operations	7,053,423.7	1,220,913.5	173.095	4.593
15.	Ontario T-Service Credits		0.0		
16.	Western T-Service		87,007.0		
17.	Forecasted Gas Costs	7,053,423.7	1,307,920.5	185.431	4.920

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
YEAR ENDED DECEMBER 31, 2013

Item #		
1.	Sendout To Operations	7,053,423.7
2.	T-Service Volumes	4,249,292.6
3.	Total Sendout	11,302,716.3
4.1	Residential Sales	3,962,575.0
4.2	Commercial Sales	2,429,591.6
4.3	Industrial Sales	434,497.9
4.4	T-Service	4,209,851.4
4.5	Rate 200 T-Service (Gazifere)	38,849.3
4.6	Rate 200 Sales (Gazifere)	123,435.7
4.7	Company Use	5,176.3
4.8	Unaccounted For (UAF)	73,887.2
4.9	Unbilled Forecast - Sales	496.3
4.10	Unbilled Forecast - T-Service	592.0
4.11	Lost and Unaccounted For (LUF)	23,763.6
4.	Total System Requirements	11,302,716.3

Witnesses: J. Sarnovsky
D. Small

SUMMARY OF STORAGE & TRANSPORTATION COSTS
FISCAL 2013

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2013	Col. 2 Fiscal 2013 Storage Charges Recovered in Fiscal 2013	Col. 3 Fiscal 2012 Storage Charges Recovered in Fiscal 2013	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2013
	Storage				
1.1	Chatham D	132.3	74.6	57.3	131.9
1.2	Injection	122.7	37.6	87.8	125.4
1.3	Withdrawal	114.2	114.2	0.0	114.2
1.4	Market Based Storage	19,592.0	10,690.2	8,747.6	19,437.8
1.5	Unutilized Transportation Costs	2,833.8	2,833.8	0.0	2,833.8
1.6	Other	827.2	827.2	0.0	827.2
1.	Total Storage	23,622.3	14,577.6	8,892.8	23,470.4
2.	Total Transportation	65,550.7	35,827.0	29,496.5	65,323.5
	Dehydration				
3.1	Demand	1,001.1	547.1	450.5	997.6
3.2	Commodity	185.2	185.2	0.0	185.2
3.	Total Dehydration	1,186.2	732.3	450.5	1,182.8
4.	Total Storage & Other Costs	90,359.3	51,137.0	38,839.7	89,976.7
	Fuel Costs				
5.1	Tecumseh	3,469.0	2,256.7	1,349.4	3,606.0
5.2	Union Storage	1,043.0	662.2	413.6	1,075.8
5.3	Union Transportation	15,815.1	15,506.8	314.5	15,821.3
5.	Total Fuel Costs	20,327.1	18,425.7	2,077.4	20,503.1
6.	Total Storage & Transportation	110,686.4	69,562.7	40,917.1	110,479.8
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				110,479.8

Witnesses: J. Sarnovsky
D. Small

MONTHLY PRICING INFORMATION

	Col. 1 21 Day Average Empress CGPR $CAD/GJ	Col. 2 21 Day Average NYMEX $US/MMBtu	Col. 3 21 Day Average Chicago $US/MMBtu	Col. 4 21 Day Average US Exchange $CAD/$US	Col. 5 $CAD/10^3m^3$ Equivalent (Note 1)
Jan-13	2.9336	3.6470	3.8141	1.0045	
Feb-13	2.9429	3.6578	3.7584	1.0051	
Mar-13	2.9318	3.6393	3.6853	1.0057	
Apr-13	2.8893	3.6019	3.6419	1.0064	
May-13	2.8938	3.6354	3.6741	1.0070	
Jun-13	2.9044	3.6770	3.6907	1.0077	
Jul-13	2.9462	3.7199	3.7357	1.0083	
Aug-13	2.9276	3.7361	3.7624	1.0089	
Sep-13	2.9732	3.7369	3.7615	1.0096	
Oct-13	3.0846	3.7738	3.8273	1.0102	
Nov-13	3.1874	3.8710	3.9363	1.0109	
Dec-13	3.3399	4.0689	4.1826	1.0115	
	2.9962	3.7304	3.7892	1.0080	112.9278
TCPL Fuel Ratio		3.52%			116.9007

(Note 1) $CAD/10^{3}m^3 = $CAD/GJ * 37.69 Mj/m3

21 Day Period **1-Feb-12** **to** **29-Feb-12**

Natural Gas Conversions

mcf times 0.028328 = 10^{3}m^3

1 Dth = 1 mcf

MMBtu times 1.055056 = GJ's

$/mcf divided by .028328 = $/10^{3}m^3

$/MMBtu divided by 1.055056 = $/GJ

$/GJ times MJ/m^3 = $/10^{3}m^3

Enbridge Gas Distribution Inc. assumes a heat content of 37.69 Mj/m^3

Witnesses: J. Sarnovsky
D. Small

GAS SUPPLY/DEMAND BALANCE

Item #		Col. 1 2013 Budget 10^3m^3	Col. 2 2012 Forecast 10^3m^3	Col. 3 2011 Estimate 10^3m^3
1.	Total Demand	11,302,716.3	11,376,395.6	11,780,281.0
	Deliveries			
2.1	Western Canadian Supplies	3,764,706.0	3,439,824.9	2,617,614.3
2.2	Peaking/Seasonal	37,998.7	37,242.5	31,852.0
2.3	Ontario Production	730.0	730.0	852.9
2.4	Chicago Supplies	1,832,109.7	1,837,120.7	1,839,134.5
2.5	Delivered Supplies	1,471,212.5	1,488,789.8	2,013,541.2
2.6	Direct Purchase Delivery	4,315,899.5	4,721,012.0	5,219,727.5
2.7	Storage (Injection)/Withdrawal	(119,939.9)	(148,324.3)	59,558.5
2.	Total Delivery	11,302,716.4	11,376,395.6	11,782,281.0

Total Demand includes both System Sales and T-Service Consumption

Witnesses: J. Sarnovsky
D. Small

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

Producing the UUF Forecast – 2013 Budget

1. This evidence describes the forecast methodology and updates the forecast of Unbilled and Unaccounted-For Gas ("UUF") for the test year. Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") asks the Ontario Energy Board (the "Board") to approve the 2013 UUF forecast of 74 180 10^3m^3 as part of the overall volumes budget, as well as the continued use of the Unaccounted For Variance Account ("UAFVA"). Deferral account evidence can be found at Exhibit D1, Tab 8, Schedule 1.

2. The UUF forecast is produced using a two-step process involving the forecast of both Unaccounted-For Gas ("UAF") and unbilled volumes. For instance, the 2013 UUF forecast is equal to the 2013 UAF forecast plus the expected difference between the December 2013 and December 2012 unbilled volumes (i.e., change in unbilled volumes). Both the UAF and unbilled volumes forecasts are produced via a statistical model.

3. UAF data for years prior to 2005 have been transformed to calendar year format in order to produce a calendar year UAF forecast. For an explanation of the transformation of volumes from fiscal to calendar year format, please see EB-2006-0034, Exhibit C1, Tab 3, Schedule 1.

Unbilled Volumes

4. As noted in paragraph 2, the UUF forecast necessitates a year-end unbilled volumes forecast for 2012 and 2013. The Company uses a regression model to forecast the level of unbilled volumes. The model relies on the high degree of correlation between volumes and degree days.

Witnesses: H. Sayyan
M. Suarez

Unaccounted For Gas Forecast

5. The Company regularly tests a variety of forecasting models in order to ensure that the UAF forecasts are as accurate as possible. These models incorporate explanatory variables to model the variability in past UAF actuals. The Company uses a regression model that features the number of unlocked customers (i.e., unlocks) as an independent variable. The rationale for including unlocks as an explanatory variable is that the greater the size of the distribution system, the greater should be UAF, holding other things constant. Thus the expectation is that the coefficient on the unlock variable (i.e., β_1 in Figure 1) will be positive.

Figure 1
UAF forecasting model specification[1]

$$UAF_t = \beta_0 + \beta_1 * LOG(ULKS)_t + \beta_2 * DUM02_t + \beta_3 * DUMNEG_t + \varepsilon_t$$

6. The model also includes variables to account for a structural change in 2002, as well as a negative UAF value. Since the UAF values are generally lower after 2002 compared to before 2002, the expectation is that the coefficient on the corresponding variables will be negative. Further, the expectation is that the variable that accounts for the negative UAF value will have a negative coefficient. Including the variable to account for the negative values in 2004 ensures that the forecast is greater than zero. As the term ‘unaccounted-for’ suggests, it is expected that billed consumption will be less than sendout volumes and thus UAF volumes should be greater than zero.

[1] The UAF model is specified as a linear equation of the following form:

UAF =	-2791702	+ 204428 * LOG(ULKS)	– 103307 * DUM02	– 58797 * DUMNEG
(t-stats in parentheses)	(-3.17)	(3.27)	(-4.22)	(-2.04)

$R^2 = 0.63$ F-statistic=9.63 Prob(F-statistic)=0.00

Witnesses: H. Sayyan
M. Suarez

7. The proposed model specification (model 'A') performs well relative to other models, as demonstrated in Table 1 provided below. It produces an in-sample forecast error of nine percent and an out-of-sample forecast error of ten percent in 2011, the last year with an available actual. Meanwhile, the other specifications yield larger errors. Figure 2 provided below gives the meaning of the independent variables in Table 1.

Table 1
UAF model specification testing results (volumes in 10^3m^3)

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*
Model	**Dependent Variable**	**Independent Variable(s)**	**2011 In-Sample Forecast**	**Percent Error (Forecast - Actual)**	**2011 Out-of-Sample Forecast**	**Percent Error (Forecast - Actual)**
A	UAF	LOG(ULKS), DUM02, DUMNEG	66,870	-8.8%	65,706	-10.4%
B	UAF	LOG(ULKS), DUM02	62,585	-14.7%	60,742	-17.2%
C	UAF	LOG(VOLPERCUST), DUM02, DUMNEG	45,419	-38.1%	41,625	-43.3%
D	UAF	LOG(ULKS), DUM02, DUMNEG, UAF(-1)	65,990	-10.0%	64,523	-12.0%
E	UAF	LOG(TSVOL), DUM02, DUMNEG	44,679	-39.1%	40,849	-44.3%
F	UAF	DUM02, DUMNEG, AR(1), MA(1)	77,750	6.0%	89,389	21.9%

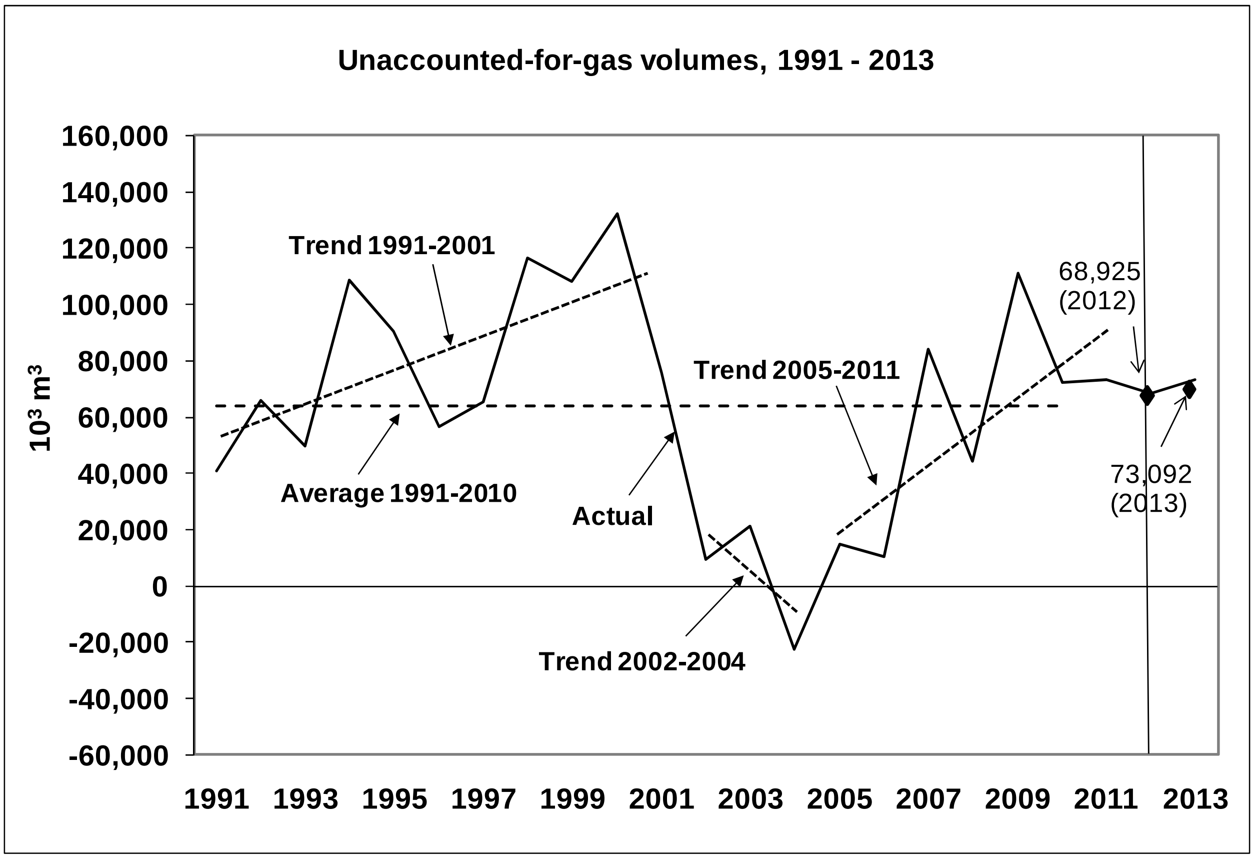
Figure 2
Mnemonics of variables used in testing

Col. 1	*Col. 2*
Mnemonic	**Definition**
ULKS	Unlocked customers/meters (unlocks)
DUM02	Dummy variable to account for 2002 structural break
DUMNEG	Dummy variable to account for negative UAF values
VOLPERCUST	Volume per general service customer
UAF(-1)	UAF lagged one year
TSVOL	T-Service volumes
AR(N)	N-th order auto-regressive term
MA(N)	N-th order moving average term

Witnesses: H. Sayyan
M. Suarez

UAF Forecast Results

8. Figure 3 provided below shows historical UAF data along with the 2011 Actual, 2012 Board Approved and 2013 Test Year forecasts. The graph also shows the 1991 to 2001 trend, the 2002 to 2011 trend and the 1991 to 2011 average.



***Forecast values are based on a regression model produced in May 2012.**

Witnesses: H. Sayyan
M. Suarez

Actual versus Board Approved– Last Five Years

9. Table 2 below presents UAF actuals along with Board Approved values for the past five years.

Table 2
UAF Actuals vs Board Approved
(10^3m^3)

Col. 1	*Col. 2*	*Col. 3*
Calendar Year	**Actual**	**Board Approved**
2006	10,274	39,162
2007	83,823	39,444
2008	44,424	39,444
2009	110,917	31,841
2010	72,104	37,795
2011	73,355	64,211

Calculation of 2013 UUF

10. The total UUF forecast is generated by adding the forecasted change in December 2013 versus December 2012 unbilled volumes to the 2013 UAF forecast. As such, the 2013 Test Year UUF forecast is as follows:

2013 UUF = (Forecast of UAF Gas) + (Change in Unbilled Gas)
= (Forecast of UAF Gas) + (Forecast of December 2013 Unbilled Gas - Forecast for December 2012 Unbilled Gas)
$= 73\ 092\ 10^3m^3 + (703\ 982\ 10^3m^3 – 702\ 894\ 10^3m^3)$
$= 73\ 092\ 10^3m^3 + 1\ 088\ 10^3m^3$
$= 74\ 180\ 10^3m^3$

Witnesses: H. Sayyan
M. Suarez

11. Table 3 below displays historical UAF and unlock data along with projection for Calendar Year 2013. The 2013 Test Year forecast UAF value is generated by the regression model.

Table 3
UAF Volumes and total unlocks, calendar 1991 to 2013
(volumes in 10^3m^3)

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	**UAF Volumes**	**Unlocks**	**Reference**
1991	40,662	1,067,691	
1992	66,028	1,104,224	
1993	49,782	1,146,420	
1994	108,765	1,188,226	
1995	90,655	1,232,989	
1996	56,739	1,274,338	
1997	65,228	1,325,700	
1998	116,376	1,376,564	
1999	108,201	1,426,783	
2000	132,021	1,479,413	
2001	75,606	1,529,651	
2002	9,284	1,580,819	
2003	21,412	1,635,855	
2004	-22,406	1,688,843	
2005	14,815	1,735,906	
2006	10,274	1,782,813	
2007	83,823	1,824,789	
2008	44,424	1,865,020	
2009	110,917	1,887,605	
2010	72,104	1,926,294	
2011	73,355	1,960,378	Ex D5 T4 S1
2012 Board Approved	68,925	1,984,734	Ex D4 T4 S1
2013 Test Year*	73,092	2,020,962	

*Forecast values are based on a regression model produced in May 2012.

Witnesses: H. Sayyan
M. Suarez

2013 Test Year Forecast versus 2012 Board Approved

12. Table 4 compares 2012 Board Approved and 2013 Test Year Forecast UAF and UUF volumes. The 2012 Board Approved UUF is equal to the 2012 Board Approved UAF plus the change in forecast unbilled gas volumes between December 2012 and December 2011.

Table 4

2013 Test Year Forecast versus 2012 Board Approved (10^3 m^3)

Col. 1	*Col. 3*	*Col. 2*
	2013 Test Year	**2012 Board Approved**
Unaccounted-for volumes	73,092	68,925
Change in unbilled	1,088	8,946
Unbilled and unaccounted-for	74,180	77,871

2011 Actual versus 2011 Board Approved

13. Table 5 compares 2011 Actual and 2011 Board Approved UAF and UUF volumes. The change in unbilled in 2011 is the actual 2011 December unbilled less the actual 2010 December unbilled.

Table 5

2011 Actual versus 2011 Board Approved Forecast (10^3 m^3)

Col. 1	*Col. 2*	*Col. 3*
	2011 Actual	**2011 Board Approved[1]**
Unaccounted-for volumes	73,355	64 211
Change in unbilled	-80,818	-174 000
Unbilled and unaccounted-for	-7,463	-109 789

[1] As per 2011 rate proceeding EB-2010-0146

Witnesses: H. Sayyan
M. Suarez

COST OF SERVICE
COMPARISON OF UTILITY COSTS AND EXPENSES
2012 ESTIMATE AND 2011 HISTORICAL

Item No.		Col. 1 2012 Estimate ($Millions)	Col. 2 2011 Historical ($Millions)	Col. 3 2012 Estimate Over/(Under) 2011 Historical ($Millions)
1.1	Gas costs charged to operations	1,515.5	1,387.8	127.7
1.2	Operations and maintenance	402.2	355.7	46.5
1.3	Depreciation	291.6	276.1	15.5
1.4	Fixed financing costs	2.3	2.9	(0.6)
1.5	Debt redemption premium amortization	0.2	0.3	(0.1)
1.6	Company share of IR agreement tax savings	25.6	22.3	3.3
1.7	Municipal and other taxes	38.8	37.0	1.8
1.0	Total costs and expenses	2,276.2	2,082.1	194.1

Witnesses: S. Kancharla
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2012 ESTIMATE AND 2011HISTORICAL

Item No.

1.1 Gas costs charged to operations - increase of $127.7 million

The increase in gas costs charged to operations in the 2012 Estimate is primarily due to the general service customer growth, the continued migration from T-service to system gas, higher TransCanada Pipelines Limited tolls for T-service, partially offset by a lower gas demand forecast resulting from a forecast of warmer weather, the continued decline in average use for general service customers, and a lower contract volume forecast. Please refer to Exhibit C1, Tab 3, Schedule 1, for the details of the gas volume budget.

1.2 Operation and maintenance - increase of $46.5 million

The increase in operation and maintenance costs in the 2012 Estimate is primarily due to: higher customer care service charges, an increase in allocated costs due to the Regulatory Cost Allocation Methodology, and higher pension expense as a result of the contribution required for the pension fund, an increase in salaries and benefits resulting from an increase in base salary and wages and an increase in staff levels, and incremental cost for the operational risk mitigation initiative.

A comparison of the 2012 Estimate to the 2011 Historical operation and maintenance costs is provided at Exhibit D1, Tab 3, Schedule 1.

Witnesses: S. Kancharla
R. Lei

1.3 Depreciation expense – increase of $15.5 Million

The increase in depreciation expense is mainly due to higher depreciable property, plant & equipment resulting from the annual capital expenditures.

1.4 Fixed financing costs – decrease of $0.6 million

The decrease is due to the decline of stand-by fee for the bank credit facility available to the Company.

1.5 Debt redemption premium amortization – decrease of $0.1 million

The decrease reflects the partial year effectiveness of the amortization as the premium will be completely amortized by July 2012 as opposed to the full year impact in 2011.

1.6 Company share of Incentive Regulation agreement tax savings– increase of $3.3 million

The increase reflects the Company's share of the agreed upon tax savings sharing in 2012 as approved in EB-2011-0277, Exhibit C, Tab 1, Schedule 4 page 2.

1.7 Municipal and other Taxes – increase of $1.8 million

The increase reflects the inflationary pressure on municipal tax rate, increased municipal taxes in growth for new mains and service connections, a new safety training facility, and gate stations. The details of municipal taxes are provided at Exhibit D1, Tab 6, Schedule 1.

Witnesses: S. Kancharla
R. Lei

Updated Evidence

COST OF SERVICE
COMPARISON OF UTILITY COSTS AND EXPENSES
2012 ESTIMATE AND 2011 ACTUAL

		Col. 1	Col. 2	Col. 3
Item No.		2012 Estimate ($Millions)	2011 Actual ($Millions)	2012 Estimate Over/(Under) 2011 Actual ($Millions)
1.1	Gas costs charged to operations	1,515.5	1,383.7	131.8
1.2	Operations and maintenance	402.2	360.5	41.7
1.3	Depreciation	291.6	276.6	15.0
1.4	Fixed financing costs	2.3	2.8	(0.5)
1.5	Debt redemption premium amortization	0.2	0.3	(0.1)
1.6	Company share of IR agreement tax savings	25.6	22.3	3.3
1.7	Municipal and other taxes	38.8	37.6	1.2
1.0	Total costs and expenses	2,276.2	2,083.8	192.4

Witnesses: S. Kancharla
R. Lei

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

2012 Board-Approved versus 2011 Actual

1. The 2012 Board Approved value for Unbilled and Unaccounted For Gas ("UUF") is 77 871 10^3m^3. This consists of 68 925 10^3m^3 UAF and 8 946 10^3m^3 change in unbilled volumes.

2. The change in unbilled volumes is a result of an increase in the level of unbilled volumes from 693 949 10^3m^3 in December 2011 to 702 895 10^3m^3 in December 2012.

3. The 2012 Board Approved UUF is calculated as follows:

2012 UUF = (Forecast UAF Gas) + (Change in Unbilled)
= (Forecast UAF Gas) + (Forecast unbilled volumes December 2012)
– (Forecast unbilled volumes December 2011)
= 68 925 10^3m^3 + (702 895 10^3m^3 – 693 949 10^3m^3)
= 68 925 10^3m^3 + 8 946 10^3m^3
= 77 871 10^3m^3

4. Table 1 compares 2012 Board Approved and 2011 Actual UAF and UUF volumes.

Table 1
2012 Board-Approved versus 2011 Actual (10^3 m^3)

Col. 1	*Col. 3*	*Col. 2*
	2012 Board-Approved[1]	**2011 Actual[2]**
Unaccounted-for volumes	68,925	73,355
Change in unbilled	8,946	-80,818
Unbilled and unaccounted-for	77,871	-7,463

[1] The 2012 Board-Approved value is from the EB-2011-0277 Settlement Agreement approved by the Board December 1, 2011.
[2] The 2011 Actual is the actual UAF value for 2011.

Witnesses: H. Sayyan
M. Suarez

COST OF SERVICE
COMPARISON OF UTILITY COSTS AND EXPENSES
2011 HISTORICAL AND 2007 BOARD APPROVED

Item No.		Col. 1 2011 Historical ($Millions)	Col. 2 2007 Board Approved ($Millions)	Col. 3 2011 Historical Over/(Under) 2007 Board Approved ($Millions)
1.1	Gas costs charged to operations	1,387.8	2,174.6	(786.8)
1.2	Operations and maintenance	355.7	326.2	29.5
1.3	Depreciation	276.1	227.3	48.8
1.4	Fixed financing costs	2.9	1.3	1.6
1.5	Debt redemption premium amortization	0.3	-	0.3
1.6	Company share of IR agreement tax savings	22.3	-	22.3
1.7	Notional utility account recovery	-	9.2	(9.2)
1.8	Municipal and other taxes	37.0	45.9	(8.9)
1.0	Total costs and expenses	2,082.1	2,784.5	(702.4)

Witnesses: S. Kancharla
R. Lei

EXPLANATION OF MAJOR VARIANCES
IN COMPARISON OF UTILITY COSTS AND EXPENSES
2011 HISTORICAL AND 2007 BOARD APPROVED

Item No.

1.1 Gas costs charged to operations - decrease of $786.8 million
The decrease in gas costs charged to operations in the 2011 Historical is principally due to a significantly lower gas prices. Please refer to Exhibit C5, Tab 2, Schedule 4 for the comparison of 2011 Historical and 2007 Board Approved.

1.2 Operation and maintenance - increase of $29.5 Million
The increase in operation and maintenance costs in the 2011 Estimate is primarily due to: higher Demand Side Management costs, increased allocation of costs due to the Regulatory Cost Allocation Methodology, an increase in salaries and wages, benefits, and short term incentive compensation resulting from an increase in base salary and wages and an increase in staff levels, increased outsourced services, and higher costs relating to safety and integrity programs, partially offset by lower customer care service charges.

1.3 Depreciation expense – increase of $48.8 Million
The increase in depreciation expense is mainly due to higher depreciable property, plant & equipment resulting from the annual capital expenditures over four years.

1.4 Fixed financing costs – increase of $1.6 Million
The increase is attributed to higher standby fee for the committed bank credit facility and higher upfront credit commitment fee over four years.

Witnesses: S. Kancharla
R. Lei

1.5 Debt redemption premium amortization – increase of $0.3 million

The increase reflects the full year amount of the amortization in 2011 as opposed to the amortization in 2007 being incorporated into the Debt Redemption Deferral Account.

1.6 Company share of Incentive Regulation ("IR") agreement tax savings– increase of $22.3 million

The increase reflects no tax saving sharing in the 2007 cost of service revenue requirement as the sharing of tax savings in the IR agreement began in 2008. The $22.3 million represents the impact of the shareholder portion of agreed tax savings on utility income in 2011 approved by the Board.

1.7 Notional utility account recovery – decrease of $9.2 Million

The Ontario Energy Board Decision (RP-2003-0203) allowed recovery of $23.9 million, after taxes, over a three year period commencing in Fiscal 2005 (October 2005 to September 2007). The decrease in the recovery of notional utility account represents that the amount was fully recovered by 2007 and no balance was outstanding subsequent to 2007.

1.8 Municipal and other taxes – decrease of $8.9 Million

The decrease is due to the elimination of capital tax in 2011 by the government, marginally offset by higher 2011 municipal tax due to increases in current value assessment as well as the roll-out of new pipeline regulated rates in 2008.

Updated Evidence

COST OF SERVICE
COMPARISON OF UTILITY COSTS AND EXPENSES
2011 ACTUAL AND 2007 BOARD APPROVED

Item No.		Col. 1 2011 Actual ($Millions)	Col. 2 2007 Board Approved ($Millions)	Col. 3 2011 Actual Over/(Under) 2007 Board Approved ($Millions)
1.1	Gas costs charged to operations	1,383.7	2,174.6	(790.9)
1.2	Operations and maintenance	360.5	326.2	34.3
1.3	Depreciation	276.6	227.3	49.3
1.4	Fixed financing costs	2.8	1.3	1.5
1.5	Debt redemption premium amortization	0.3	-	0.3
1.6	Company share of IR agreement tax savings	22.3	-	22.3
1.7	Notional utility account recovery	-	9.2	(9.2)
1.8	Municipal and other taxes	37.6	45.9	(8.3)
1.0	Total costs and expenses	2,083.8	2,784.5	(700.7)

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
2011 Actual Year vs Historical Year

Line No.	Particulars ($ 000's)	Actual 2011	Historical 2011	2011 Actual Over(Under) 2011 Historical
1.	Finance	$ 6,196	$ 6,393	$ (196)
2.	Risk Management	2,459	1,656	803
3.	Customer Care Service Charges	64,190	65,844	(1,654)
4.	Customer Care Internal Costs	7,360	8,847	(1,487)
5.	Provision for Uncollectibles	21,542	16,794	4,748
6.	Energy Supply, Storage Development, Regulatory	11,757	13,007	(1,249)
7.	Legal and Corporate Security	4,146	4,800	(654)
8.	Operations	59,195	58,747	448
9.	Information Technology	30,893	30,957	(63)
10.	Business Development & Customer Strategy (excluding DSM)	8,339	10,003	(1,664)
11.	Human Resources (excluding benefits and pensions)	20,031	18,384	1,647
12.	Benefits	24,264	23,193	1,071
13.	Pensions	3,224	3,224	-
14.	Pipeline Integrity & Safety	29,695	29,547	148
15.	Public and Government Affairs	7,381	7,252	128
16.	Non Departmental Expenses	31,130	28,030	3,099
17.	Corporate Allocations (including direct costs)	43,440	41,822	1,618
18.	Subtotal	375,243	368,500	6,742
19.	Capitalization (A&G)	(24,482)	(25,348)	866
20.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	350,761	343,152	7,608
21.	Demand Side Management Programs (DSM)	26,708	28,074	(1,366)
22.	Conservation Services	7,292	6,958	333
23.	Total Net Utility O&M Expense before Eliminations	384,760	378,185	6,575
24.	Regulatory Eliminations			
25.	To eliminate Corporate Cost Allocations above RCAM	(16,725)	(15,107)	(1,618)
26.	To eliminate Conservation Services and Overheads	(7,292)	(7,407)	115
27.	Incremental O&M Allocated to Unregulated Storage	(233)	-	(233)
28.	Total Eliminations	(24,249)	(22,514)	(1,736)
29.	Total Net Utility O&M Expense	$ 360,511	$ 355,671	$ 4,840

Notes:
1) Departmental O&M costs are net of capitalization, non-utility,and other utility adjustments.

Witness: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
2011 Actual Year vs. 2007 Board Approved

Line No.	Particulars ($000's)	Actual 2011 (a)	Board Approved 2007 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$ 141,477	$ 136,513	$ 4,965	3.6%
2.	Benefits	24,263	21,295	2,968	13.9%
3.	Pension	3,225	1,745	1,480	84.8%
4.	Short Term Incentive Program	26,006	14,730	11,276	76.6%
5.	Employee Training and Development	5,564	3,303	2,260	68.4%
6.	Materials and Supplies	5,202	9,040	(3,838)	-42.5%
7.	Outside Services	63,608	45,845	17,763	38.7%
8.	Regulatory Costs	4,824	7,603	(2,779)	-36.6%
9.	Consulting	5,026	15,073	(10,047)	-66.7%
10.	Repairs and Maintenance	1,387	1,166	221	18.9%
11.	Fleet	9,005	10,506	(1,502)	-14.3%
12.	Rents and Leases	7,286	8,995	(1,709)	-19.0%
13.	Telecommunications	3,136	3,615	(479)	-13.3%
14.	Travel and Other Business Expenses	3,540	3,972	(432)	-10.9%
15.	Memberships	3,978	2,852	1,127	39.5%
16.	Claims, Damages and Legal Fees	1,599	1,510	89	5.9%
17.	Customer Care Service Charges (including CIS)	79,199	90,800	(11,601)	-12.8%
18.	Interest on Security Deposits	1,036	1,718	(682)	-39.7%
19.	Provision for Uncollectibles	21,542	15,105	6,438	42.6%
20.	Consumers Gas Ltd Charges	-	371	(371)	-100.0%
21.	Internal Allocations and Recoveries	(25,739)	(17,175)	(8,564)	49.9%
22.	Corporate Cost Allocations (including direct costs)	43,440	18,100	25,340	140.0%
23.	Other	6,793	7,010	(217)	-3.1%
24.	Subtotal	435,394	403,691	31,703	7.9%
25.	Capitalization (A&G)	(24,482)	(19,134)	(5,348)	28.0%
26.	Capitalization	(55,260)	(57,628)	2,368	-4.1%
27.	Non-Utility Allocations	(4,891)	(22,729)	17,838	-78.5%
28.	Total Net Utility O&M Expense, excl. DSM, Conservation	350,761	304,200	46,561	15.3%
29.	Demand Side Management Programs (DSM)	26,708	22,000	4,708	21.4%
30.	Conservation Services	7,292	-	7,292	
31.	Total Net Utility O&M Expense before Eliminations	384,761	326,200	58,561	18.0%
32.	Regulatory Eliminations				
33.	To eliminate Corporate Cost Allocations above RCAM	(16,725)	-	(16,725)	
34.	To eliminate Conservation Services and Overheads	(7,292)	-	(7,292)	
35.	Incremental O&M Allocated to Unregulated Storage	(233)	-	(233)	
36.	Total Eliminations	(24,250)	-	(24,250)	
37.	Total Net Utility O&M Expense	$ 360,511	$ 326,200	$ 34,311	10.5%

Notes:
1). The 2007 Board Approved O&M reflects the $37.9 million reduction from the 2007 Budget filed by the Company.
2). The Salaries and Wages (Line 1) exclude the salaries and wages embedded in the following line items because they have their own discrete regulatory treatments: Customer care service charges (Line 17), DSM (Line 29), and Conservation services (Line 30).

Witness: S. Kancharla
R. Lei

UNBILLED AND UNACCOUNTED-FOR GAS VOLUMES

2011 Actual versus 2011 Board Approved

1. In 2011 Actual, the Unbilled and Unaccounted for Gas (“UUF”) is -7,463 10^3m^3. This consists of 73,355 10^3m^3 Unaccounted For Gas (“UAF”) and -80,818 10^3m^3 change in unbilled volumes.

2. The change in unbilled volumes is a result of a decrease in the level of unbilled volumes from 834,891 10^3m^3 in December 2010 to 754,073 10^3m^3 in December 2011, due primarily to warmer weather in December 2011.

3. The 2011 Actual UUF is calculated as follows:

2011 UUF = (Actual UAF Gas) + (Change in Unbilled)
= (Actual UAF Gas) + (Actual unbilled volumes December 2011)
– (Actual unbilled volumes December 2010)
= 73,355 10^3m^3 + (754,073$10^3m^3$ – 834,891 10^3m^3)
= 73,355 10^3m^3 – 80,818 10^3m^3
= -7,463 10^3m^3

4. Table 1 compares 2011 Actual and 2011 Ontario Energy Board Approved UAF and UUF volumes.

Table 1
2011 Actual versus 2011 Board Approved Forecast (10^3 m^3)

Col. 1	*Col. 2*	*Col. 3*
	2011 Actual	**2011 Board Approved**[1]
Unaccounted-for volumes	73,355	64 211
Change in unbilled	-80,818	-174 000
Unbilled and unaccounted-for	-7,463	-109 789

[1] As per 2011 rate proceeding EB-2010-0146

Witnesses: H. Sayyan
M. Suarez

IMPACT STATEMENT NUMBER 1

1. This exhibit has been prepared and filed in order to reflect the impact of certain changes which are required in Enbridge Gas Distribution's 2013 rate application.

   The required changes are in relation to the following:

   a) Impact of 2011 actual versus estimated results used in original filing
   b) Change in expected 2013 corporate income tax rates
   c) Change in expected 2013 Annual Pension Cost
   d) Adoption of the storage cost allocation study (Black & Veatch recommendations)
   e) Update of the Regulatory Cost Allocation Methodology (RCAM) results (MNP LLP recommendations)
   f) Update reflecting accepted increase in DSM costs
   g) Update of the forecast allowed Return on Equity

2. The impacts of the above noted adjustments are shown in Column 2 in each of the attached Schedules 2 and 3, and in Column 4 of Schedule 5 which shows a new total revenue requirement and deficiency first excluding, and then including the impact of the Customer Care / CIS settlement. The adjustments are in relation to utility income, rate base, income tax, and revenue requirement amounts exclusive of the Customer Care / CIS settlement agreement amounts and impacts.

Required changes

3. EGD has updated the 2013 Test Year results by replacing the 2011 estimate results, which were the starting point for the 2012 Bridge Year and 2013 Test Year results as originally filed 2012-01-31, with 2011 actual fiscal year results. The update takes into consideration the impacts of 2011 actual results in property, plant, and equipment and accumulated depreciation and any other working capital item, along with the impact of 2011 actual information in the 2013 degree day forecast methodology and volumetric and customer unlock forecasts. In addition to the impacts of these changes in the development of the updated revenue requirement,

EGD has also updated the revenue and gas cost related forecast elements to reflect April 1, 2012 Board Approved rates and gas prices.

4. In March 2012, the provincial government presented its budget wherein it announced that it would freeze the corporate income tax rate at 11.50%. Ontario's corporate income tax rate was scheduled to fall to 11% on July 1, 2012 and to 10% on July 1, 2013. The corporate income tax rate freeze will increase EGD's combined federal and provincial corporate income tax rate for 2012 and 2013 to 26.5%. This results in a 1% increase to the 2013 corporate income tax rate in comparison to the 25.5% used in the original evidence filed 2012-01-31, Exhibit D3, Tab 1, Schedule 1, page 3, Line 14, Columns 1 and 2.

5. EGD is incorporating the most recent forecast of pension expense for fiscal 2013 received from its pension actuary, Mercer (Canada) Limited. The 2013 forecast pension cost has increased by $9.6 million from the $27.7 million included in the original filing to $37.3 million. Of the $9.6 million change, approximately $7.6 million represents an annual O&M expense increase with the remaining $2 million to be capitalized as administrative and general overhead.

6. EGD has filed the results of the storage cost allocation study performed by Black and Veatch at Exhibit D2, Tab 5, Schedule 1, 2012-05-18, which was not available at the time of the 2013 original evidence filing date. The impact of the adoption of the findings in the study results in an increase in the costs allocated to unregulated storage and a commensurate reduction in utility O&M of approximately $0.2 million.

7. EGD has filed the results of the Regulatory Cost Allocation Methodology ("RCAM") review performed by Myers Norris Penny LLP ("MNP LLP") at Exhibit D2, Tab 1, Schedule 1, 2012-05-18, which was not available at the time of the 2013 original evidence filing date. The impact of the adoption of the findings in the study results in an RCAM amount included with O&M of $32.1 million, an increase of $1.8 million from the $30.3 million included in O&M in the original filing.

8. EGD has updated the level of DSM costs included in utility O&M to $31.4 million an increase of $2.8 million from the $28.6 million included in the original filing. As indicated in evidence in EB-2011-0354 at Exhibit D1, Tab 7, Schedule 1, page 2, Paragraph 4 and as included in the Settlement Agreement filed in that proceeding and approved by the Board on February 9, 2012, the DSM budget for 2013 is $31.4 million.

9. As explained in Exhibit E2, Tab 1, Schedule 1, Updated 2012-05-31, the Company has updated the formula forecast Return on Equity ("ROE") used in this impact statement to 9.03%, which is based on data inputs from March 2012, resulting in a reduction in the deficiency of approximately $9.1 million. The 9.03% ROE being used is only a current update which is to be replaced in the eventual final Rate Order and resulting rates with an ROE calculated on data inputs from September 2012.

10. As a result of all of the above noted adjustments, the 2013 gross deficiency, excluding the impacts of the Customer Care / CIS approved settlement, becomes $81.6 million which is an increase of $1.3 million as compared to the original filed deficiency of $80.3 million shown in the attached Schedule 2, Columns 1, 2, & 3. The $11 million deficiency impact of the Customer Care / CIS approved settlement shown in Column 4 of Schedule 2, is not impacted by this update, however the total overall deficiency increases by $1.3 million to $92.6 million as shown in Column 5 of Schedule 2.

CHANGE IN REVENUE REQUIREMENT
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS As Filed 2012-01-31 F3.T1.S1.P2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Impact Statement Number 1	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Impact Statement Number 1 EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	4,120.3	(16.7)	4,103.6	70.5	4,174.1
2.	Required rate of return	7.35	(0.16)	7.19	6.44	7.18
3.		302.8	(7.8)	295.0	4.6	299.6
	Cost of service					
4.	Gas costs	1,548.6	(240.7)	1,307.9	-	1,307.9
5.	Operation and maintenance	336.7	12.0	348.7	89.4	438.1
6.	Depreciation and amortization	289.6	(1.5)	288.1	12.7	300.8
7.	Fixed financing costs	2.3	-	2.3	-	2.3
8.	Debt redemption premium amortization	-	-	-	-	-
9.	Company share of IR agreement tax savings	-	-	-	-	-
10.	Municipal and other taxes	40.1	-	40.1	-	40.1
11.		2,217.3	(230.2)	1,987.1	102.1	2,089.2
	Miscellaneous operating and non-operating revenue					
12.	Other operating revenue	(38.3)	-	(38.3)	-	(38.3)
13.	Interest and property rental	-	-	-	-	-
14.	Other income	(0.7)	-	(0.7)	-	(0.7)
15.		(39.0)	-	(39.0)	-	(39.0)
	Income taxes on earnings					
16.	Excluding tax shield	73.2	(0.1)	73.1	9.0	82.1
17.	Tax shield provided by interest expense	(34.6)	(1.2)	(35.8)	(0.9)	(36.7)
18.		38.6	(1.3)	37.3	8.1	45.4
	Taxes on sufficiency / (deficiency)					
19.	Gross sufficiency / (deficiency)	(80.3)	(1.3)	(81.6)	-	(81.6)
20.	Net sufficiency / (deficiency)	(59.8)	(0.2)	(60.0)	-	(60.0)
21.		20.5	1.1	21.6	-	21.6
22.	**Sub-total revenue requirement**	2,540.2	(238.2)	2,302.0	114.8	2,416.8
23.	Customer Care Rate Smoothing V/A Adjustmen	-	-	-	(4.6)	(4.6)
24.	**Total revenue requirement**	2,540.2	(238.2)	2,302.0	110.2	2,412.2
	Revenue at existing Rates					
25.	Gas sales	2,137.5	(213.6)	1,923.9	80.2	2,004.1
26.	Transportation service	320.6	(25.7)	294.9	19.0	313.9
27.	Transmission, compression and storage	1.7	-	1.7	-	1.7
28.	Rounding adjustment	0.1	(0.2)	(0.1)	-	(0.1)
29.	Revenue at existing rates	2,459.9	(239.5)	2,220.4	99.2	2,319.6
30.	**Gross revenue sufficiency / (deficiency)**	(80.3)	(1.3)	(81.6)	(11.0)	(92.6)

Note 1: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 1, page 2, Filed: 2012-01-31.
Note 2: Information from Col. 3 of Exhibit F3, Tab 1, Schedule 1, page 2, Filed: 2012-01-31.

Witness: K. Culbert

UTILITY RATE BASE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS As Filed 2012-01-31 F3.T1.S3 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Utility Rate Base ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Total Adjusted Rate Base Including CIS ($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	6,631.9	13.7	6,645.6	127.1	6,772.7
2.	Accumulated depreciation	(2,767.1)	9.1	(2,758.0)	(56.6)	(2,814.6)
3.		3,864.8	22.8	3,887.6	70.5	3,958.1
	Allowance for Working Capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
6.	Materials and supplies	31.9	-	31.9	-	31.9
7.	Mortgages receivable	0.2	-	0.2	-	0.2
8.	Customer security deposits	(68.7)	-	(68.7)	-	(68.7)
9.	Prepaid expenses	1.8	-	1.8	-	1.8
10.	Gas in storage	288.6	(39.3)	249.3	-	249.3
11.	Working cash allowance	0.4	(0.2)	0.2	-	0.2
12.	Total Working Capital	255.5	(39.5)	216.0	-	216.0
13.	Utility Rate Base	4,120.3	(16.7)	4,103.6	70.5	4,174.1

Note 1: Information from Col. 1 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2012-01-31.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 3, page 1, Filed: 2012-01-31.

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	13.7	Cost or redetermined value Change is due to the impact of updating closing 2011 p.p.&e balances to actuals versus the closing 2011 estimated balances used in the original filing, along with $2 million of increased A&G overhead capitalization in 2013 in relation to the forecast pension cost increase included in the update.
2.	9.1	Accumulated depreciation Change is due to the impact of updating closing 2011 acc. depr. balances to actuals versus the closing 2011 estimated balances used in the original filing.
10.	(39.3)	Gas in storage Change is due to the impact of the updating of 2013 forecast volumes and from the use of updated April 1, 2012 gas prices.
11.	(0.2)	Working cash allowance Change is due to the impact within working cash of the update to each of gas cost and O&M.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2013 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		1,316.5	4.0	14.4
2.	Items not subject to working cash allowance (Note 1)		(8.6)		
3.	Gas costs charged to operations	M1.T1.S4.P1.Col.3	1,307.9		
4.	Operation and Maintenance	M1.T1.S4.P1.Col.3	348.7		
5.	Less: Storage costs		(7.9)		
6.	Operation and maintenance costs subject to working cash		340.8		
7.	Ancillary customer services		-		
8.			340.8	(18.7)	(17.5)
9.	Sub-total				(3.1)
10.	Storage costs		7.9	62.5	1.4
11.	Storage municipal and capital taxes		2.2	24.4	0.1
12.	Sub-total				1.5
13.	Goods and services tax				1.8
14.	Total working cash allowance				0.2

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

Witness: K. Culbert

GAS IN STORAGE
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2013 TEST YEAR

		Col. 1		Col. 2		Col. 3	
Line No.		Volume	As Filed 2012-01-31 B3.T1.S3	Adjustments	Adjustments	Adjusted Volume	Adjusted Value
		10*6 M*3	($Millions)	10*6 M*3	($Millions)	10*6 M*3	($Millions)
1.	January 1	1,424.6	380.6	0.5	(52.2)	1,425.1	328.4
2.	January 31	867.7	242.2	4.9	(30.5)	872.6	211.7
3.	February	439.8	134.0	7.0	(13.9)	446.8	120.1
4.	March	105.3	55.1	(9.4)	(3.4)	95.9	51.7
5.	April	46.0	49.6	(1.6)	0.6	44.4	50.2
6.	May	332.6	115.5	(1.7)	(10.1)	330.9	105.4
7.	June	709.7	200.7	10.3	(22.5)	720.0	178.2
8.	July	1,219.7	312.0	21.5	(39.9)	1,241.2	272.1
9.	August	1,732.9	423.9	30.9	(57.6)	1,763.8	366.3
10.	September	2,154.6	517.5	(13.5)	(80.2)	2,141.1	437.3
11.	October	2,261.5	547.0	(14.8)	(84.4)	2,246.7	462.6
12.	November	1,979.7	487.5	(22.5)	(75.3)	1,957.2	412.2
13.	December	1,495.8	374.9	(17.4)	(56.3)	1,478.4	318.6
14.	Avg. of monthly avgs.	1,109.1	288.6	0.2	(39.3)	1,109.4	249.3

Witness: K. Culbert

UTILITY INCOME
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS As Filed 2012-01-31 F3.T1.S2 (Note 1)	Col. 2 Adjustments	Col. 3 Excl. CIS Adjusted Utility Income	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Adjusted Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	2,137.5	(213.6)	1,923.9	80.2	2,004.1
2.	Transportation of gas	320.6	(25.7)	294.9	19.0	313.9
3.	Transmission, compression and storage revenu	1.7	-	1.7	-	1.7
4.	Other operating revenue	38.3	-	38.3	-	38.3
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.7	-	0.7	-	0.7
7.	Total operating revenue	2,498.8	(239.3)	2,259.5	99.2	2,358.7
8.	Gas costs	1,548.6	(240.7)	1,307.9	-	1,307.9
9.	Operation and maintenance	336.7	12.0	348.7	89.4	438.1
10.	Depreciation and amortization expense	289.6	(1.5)	288.1	12.7	300.8
11.	Fixed financing costs	2.3	-	2.3	-	2.3
12.	Debt redemption premium amortization	-	-	-	-	-
13.	Company share of IR agreement tax savings	-	-	-	-	-
14.	Municipal and other taxes	40.1	-	40.1	-	40.1
15.	Interest and financing amortization expense	-	-	-	-	-
16.	Other interest expense	-	-	-	-	-
17.	Total costs and expenses	2,217.3	(230.2)	1,987.1	102.1	2,089.2
18.	Ontario utility income before income taxes	281.5	(9.1)	272.4	(2.9)	269.5
19.	Income tax expense	38.6	(1.3)	37.3	8.1	45.4
20.	Utility net income	242.9	(7.8)	235.1	(11.0)	224.1

Note 1: Information from Col. 1 of Exhibit F3, Tab 1, Schedule 2, page 1, Filed: 2012-01-31.
Note 2: Information from Col. 2 of Exhibit F3, Tab 1, Schedule 2, page 1, Filed: 2012-01-31.

Witness: K. Culbert

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2013 TEST YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	(213.6)	Gas sales
		Change is due to the impact of updating 2013 forecast volumes to reflect the impact of 2011 actual results within, degree days, customer unlocks, an update of the large volume forecast and the use of April 1, 2012 Board Approved rates.
2.	(25.7)	Transportation of gas
		Change is due to the impact of updating 2013 forecast volumes to reflect the impact of 2011 actual results within, degree days, customer unlocks, an update of the large volume forecast and the use of April 1, 2012 Board Approved rates.
8.	(240.7)	Gas costs
		Change is due to the impact of updating forecast gas cost as a result of the update of 2013 forecast volumes and the use of April 1, 2012 Board Approved rates and gas prices.
9.	12.0	Operation and maintenance
		Change is due to increases of $2.8M in DSM costs, $1.8M in RCAM costs and $7.6M (net) of pension costs as compared to amounts in the original filing. A partly offsetting reduction of $0.2M in utility O&M results from an increased allocation of costs to unregulated storage as a result of adopting the findings in the Black & Veatch study.
10.	(1.5)	Depreciation and amortization expense
		Change is due to the use of 2011 actual p.p.& e. as a starting point for the 2012 Bridge Year and 2013 Test Year rate base development versus the 2011 estimate used within the original filing. While 2011 actual gross p.p. & e. increased versus the estimate due to increases in mains and services, decreases in computer equipment contributed to an overall decrease in depreciation due to higher depreciation rates in computer equipment versus those within mains and services.
19.	(1.3)	Income tax expense
		Change is the result of numerous factors. While the anticpated provincial tax rate has been increased by 1% to reflect the March 2012 provincial budget, the impact of all of the above noted changes along with an increase in immediate tax deductibles associated with the increased pension capitalized costs results in an overall forecast decreased income tax expense.

Witness: K. Culbert

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2013 TEST YEAR

Line No.		Col. 1 Excl. CIS As Filed 2012-01-31 D3.T1.S1.P3 (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Utility Tax ($Millions)
1.	Utility income before income taxes (M1, T1, S3, P1)	281.5	(9.1)	272.4
	Add			
2.	Depreciation and amortization	289.6	(1.5)	288.1
3.	Other non-deductible items	2.2	-	2.2
4.	Total Add Back	291.8	(1.5)	290.3
5.	Sub total	573.3	(10.6)	562.7
	Deduct			
6.	Capital cost allowance - Federal	239.0	(1.8)	237.2
7.	Capital cost allowance - Provincial	239.0	(1.8)	237.2
8.	Items capitalized for regulatory purposes	44.3	2.0	46.3
9.	Deduction for "grossed up" Part VI.1 tax	5.0	-	5.0
10.	Amortization of share/debenture issue expense	3.6	-	3.6
11.	Amortization of cumulative eligible capital	0.4	-	0.4
12.	Amortization of C.D.E. and C.O.G.P.E	0.4	-	0.4
13.	Total Deduction - Federal	292.7	0.2	292.9
14.	Total Deduction - Provincial	292.7	0.2	292.9
15.	Taxable income - Federal	280.6	(10.8)	269.8
16.	Taxable income - Provincial	280.6	(10.8)	269.8
17.	Income tax rate - Federal	15.00%	0.00%	15.00%
18.	Income tax rate - Provincial	10.50%	1.00%	11.50%
19.	Income tax provision - Federal	42.1	(1.6)	40.5
20.	Income tax provision - Provincial	29.5	1.5	31.0
21.	Income tax provision - combined	71.6	(0.1)	71.5
22.	Part V1.1 tax			1.7
23.	Investment tax credit			(0.1)
24.	Total taxes excluding tax shield on interest expense			73.1
	Tax shield on interest expense			
25.	Rate base (M1.T1.S2.P1)			4,103.6
26.	Return component of debt (M1.T1.S4.P1)			3.30%
27.	Interest expense			135.2
28.	Combined tax rate			26.50%
29.	Income tax credit			(35.8)
30.	Total income taxes			37.3

Note 1: Information from Col. 1 and Col. 2 of Exhibit D3, Tab 1, Schedule 1, page 3, Filed: 2012-01-31.

Witness: K. Culbert

UTILITY CAPITAL STRUCTURE
2013 TEST YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,312.8	56.36	5.90	3.325
2.	Short term debt/(investment)	(32.7)	(0.80)	3.70	(0.030)
3.		2,280.1	55.56		3.295
4.	Preference shares	100.0	2.44	4.16	0.102
5.	Common equity	1,723.5	42.00	9.03	3.793
6.		4,103.6	100.00		7.190
7.	Utility income	($Millions)			235.1
8.	Rate base	($Millions)			4,103.6
9.	Indicated rate of return				5.729%
10.	(Deficiency) in rate of return				(1.461)%
11.	Net (deficiency)	($Millions)			(60.0)
12.	Gross (deficiency)	($Millions)			(81.6)
13.	Customer Care/CIS deficiency	($Millions)			(11.0)
14.	Total gross (deficiency)	($Millions)			(92.6)
15.	Revenue at existing rates	($Millions)			2,319.6
16.	Revenue requirement	($Millions)			2,412.2
17.	Total gross revenue (deficiency)	($Millions)			(92.6)

Witness: K. Culbert