EB-2011-0210

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

LONDON PROPERTY MANAGEMENT ASSOCIATION

(“LPMA”)

ARGUMENT COMPENDIUM

4/ PARKWAY WEST PROJECT FACILITIES DESCRIPTION

The Parkway West Project facilities are comprised of three components that are proposed to be constructed over a three year period. These facilities will allow Union to meet export demand on a design day to Parkway (TCPL) and Parkway (Consumers) under an outage of the major components of the existing Parkway compression station.

1. Parkway West Land Purchase – 2012: $15.0 million
2. Parkway West Metering and Headers – 2013: $80.0 million
3. Parkway West Loss of Critical Unit Protection – 2014: $120.0 million

5/ PARKWAY WEST TIMING AND DEVELOPMENT

5.1/ Parkway West Land Purchase

The existing Parkway site is confined by the Ninth Line and housing developments to the east, a proposed development to the south, Highway 407 to the west and Derry Road to the north. Union plans to purchase land in 2012 for the Parkway West site across Highway 407 to the west of the existing Parkway site.

5.2/ Parkway West Metering and Headers

To increase reliability for deliveries to the GTA and to markets east, Union proposes to install i) headers and custody transfer metering to connect the Dawn to Parkway system to the EGD system at the proposed Parkway West station, which will provide EGD with a secure feed in the event of an outage of the existing Parkway (Consumers) feed; and ii) headers to connect the LCU compression to the Dawn to Parkway system and the TCPL system at the proposed Parkway

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	Paul Sommerville	**Member**
	Karen Taylor	**Member**

So the LCU, we started looking at LCU, loss of critical unit coverage, as early as 2010. And, really, it is a result of increased flows through Parkway.

In 2005, Parkway discharged about a half a pJ a day into the TCPL system. Today it is about four times that, and we predict that to grow to about 3 pJs per day. And that's -- really, it's the only spot in our system and, as near as we can tell, in the transmission system in Ontario that is without loss of critical unit protection.

The second feed into Enbridge, we started discussing with Enbridge some reliability concerns that they had about feeding their system, and it was an item that Enbridge had brought up in discussions. As part of those discussions, Enbridge had looked at a third feed into the Toronto area, into the GTA.

We talked about Parkway West and a second feed for that Parkway (Cons) and Lisgar as a means of satisfying the reliability for the Parkway (Cons) and Lisgar volumes.

MR. SMITH: Can you just tell me the approvals being sought by Union in this proceeding in relation to the project?

MR. REDFORD: We are seeking no approvals.

MR. SMITH: Okay. That being the case, when do you anticipate seeing approvals?

MR. REDFORD: We would file a leave to construct application in September or October of this year for the components of the project which would be typically covered under leave to construct. We would look for approval for

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	Paul Sommerville	**Member**
	Karen Taylor	**Member**

stations? Is it customers or volumes? Or something else?
MR. GARDINER: Can you give me the reference?
MR. AIKEN: Yes. It is page 2 of Exhibit J.C-2-4-1.
MR. GARDINER: Thank you.
MR. AIKEN: And it is in the second paragraph to the response to part (a), and it is on the screen.
If it helps, it is an interrogatory from VECC.
MS. HARE: Do you have it on the screen, Mr. Gardiner?
MR. GARDINER: Yes, I have it now. Thank you.
The weights are volumetric.
MR. AIKEN: Would you undertake to provide the weights that were used, in other words what percent? For example what person of the certain heating degree-days are from Windsor, London, et cetera?
MR. GARDINER: Yes, I can.
MR. SMITH: Yes, we will do that.
MR. MILLAR: Undertaking J1.1. I think it is probably clear from the record what the undertaking is, to provide the weights on a station-by-station basis. Is that correct, Mr. Aiken?
MR. AIKEN: Yes. Thank you.
UNDERTAKING NO. J1.1: TO PROVIDE PERCENTAGE OF WEIGHTS ON A STATION-BY-STATION BASIS.
MR. AIKEN: Now, you indicated earlier, Mr. Gardiner, that the -- that there is a higher degree of correlation between each of these weather stations and that of Pearson Airport.
Are you aware that Enbridge has three distribution

areas in Ontario?

MR. GARDINER: Yes, I am.

MR. AIKEN: And can you describe geographically where those areas are?

MR. GARDINER: There is the Greater Toronto Area, which we are in presently, there is the Niagara region, and there's the Ottawa region.

MR. AIKEN: Do you believe that Union's distribution regions are equally as or more diverse weather-wise than those of Enbridge?

MR. GARDINER: Yes. We serve the north and the northwest, from International Falls, Thunder Bay, Wawa and a few other communities up north, North Bay, Sudbury. Further north, we have heating degree-days in the northwest that are above 6,000 annually.

MR. AIKEN: Are you aware that in their 2007 rates proceeding, which was EB-2006-0034, that Enbridge proposed and the Board accepted a different heating degree-day forecasting methodology for each of its three regions?

MR. GARDINER: Yes, I am aware of that.

MR. AIKEN: Now, in that proceeding -- and in fact in Enbridge's current rates proceeding, which is EB-2011-0354 -- Enbridge reviewed a total of nine forecasting methodologies.

And I will give you the reference for that. It is table 1 of Exhibit C2, tab 3, schedule 1, in their filing.

I will read them for the record. They are the naive methodology, the 10-year moving average, the 20-year moving average, the 30-year moving average, the 20-year trend, the 50/50 weighting, which is a 20-year trend and the 30-year average, de Bever methodology, de Bever with trend, and the Energy Probe methodology.

With the exception of the 30-year moving average, the 20-year trend, and weighting of the two, did Union investigate the use of any of these alternatives as part of its proposal in this proceeding?

MR. GARDINER: The evidence before you is based on analysis of the 20-year trend versus the current blend, which we have been using since the decisions in 2007.

Given that Union Gas had examined the other methodologies back in 2004 and found the 20-year declining trend to be the superior methodology, and then given that Enbridge also went forward and analyzed the different methodologies and the 20-year declining trend was approved for the GTA region, which sets a precedent, and given that our analysis that we have done, an additional eight years of analysis since 2004, confirms the strength of the 20-year declining trend, that's why we looked at that methodology.

MR. AIKEN: So I take it your response is, no, you didn't attempt to investigate these other methodologies that Enbridge has reviewed, two of which have been approved by the Board, other than the 20-year trend; is that correct?

MR. SMITH: With respect, that is not an accurate summary of the witness's evidence, Mr. Aiken.

MR. AIKEN: Then I will ask the question again.

Has Union in this proceeding investigated the other six methodologies that Enbridge has reviewed?

MR. GARDINER: We did not look at the six that Enbridge investigated. We recognized that in 2004 we looked at numerous methodologies. In 2004 we got a blended methodology, which sort of indicated to Union Gas that the concept of the 20-year declining trend was a valid one.

From 2004 to 2007, the Board in its decision allowed Union Gas to increase the percentages to 55/45, and we did so.

In this rate case, we have an extra eight years since 2004. We got to the bottom line: Blend versus 20-year trend, which one is more accurate? The 20-year trend.

MR. AIKEN: So I take it from that response you did not investigate the other two methodologies that the Board approved for Enbridge in 2007?

MR. GARDINER: I did not.

MR. AIKEN: Okay. Now, how did Union land on a trend methodology that used 20 years? In other words, why not ten? Why not 18?

MR. GARDINER: This comes back to the work that was done for the 2004 rate case. Mr. Steven Root, who is one of the external consultants, had advised us to look at a 20-year period. We had examined a 30-year declining trend.

And based on the evidence -- based on the consultation, I should say, from Mr. Root, 20 years was selected.

MR. AIKEN: So then my understanding is that you didn't investigate, as part of the methodology for this proceeding, the trend year methodology with other than 20 years of length?

MR. GARDINER: If I may refresh my memory?

In 2004 we looked at the 20-year trend, the 30-year trend and a 20-year trend with forecast information.

MR. AIKEN: But with your additional eight years of data, you didn't go back and look at those again?

MR. GARDINER: No, we did not.

MR. AIKEN: Okay. Now, if you could turn to page 1 in the LPMA compendium, this is the graph of the northern and southern degree days for 1992 through 2011. The data was taken from the Excel file titled "2013 Regional Data File April 2012", and specifically at the Toronto Union HDD correlations tab, that Excel file was filed in response to Exhibit J.C-2-2-1.

Now, when I look at this graph for the last 20 years of actual heating degree days, one thing jumps out to me. There seem to be two distinct periods for both the north and the south. The first period is 1992 through 1997. Over these six years, the degree days are relatively stable and there does not appear to be much of a trend.

Would you agree with that?

MR. GARDINER: I disagree.

MR. AIKEN: Okay. Is there a statistically significant trend between 1992 and 1997?

MR. GARDINER: No. I will go back to the testing

MR. AIKEN: Did you look at adding any other explanatory variables, other than the trend variable, in the 20-year trend methodology?

MR. GARDINER: Because the 20-year declining trend methodology is simple, and that was one of the features of developing a weather normal, there only is a time variable in the equation.

MR. AIKEN: Okay. Now, in your residential, commercial and industrial equations - these are the average use and the volumetric equations - you used a number of dummy variables; is that correct?

MR. GARDINER: That is correct.

MR. AIKEN: Can you explain why dummy variables are used?

MR. GARDINER: Well, dummy variables can be used for two purposes. One, if in the historical data there are observations that are real outliers, in the sense that when you look at the data they are unique and beyond the sort of cyclical pattern that you have in usage data, that is one purpose. So you can address the fact that there was a very high level or a very low level in the monthly data series.

The other use of the structural dummy variable is if you see a step in the pattern or it could be also to deal with summer base load -- summer month consumption.

MR. AIKEN: So your last point is that dummy variables can be used to model a structural change?

MR. GARDINER: Correct.

MR. AIKEN: Okay. So then looking back at the graph on page 1 of the compendium -- and we discussed this before the lunch break, the potential break between 1992 and '97 data, and the years that follow it.

So my question is this: Did you test the 20-year trend equation to see if a better fit could be obtained by including a dummy variable to model the structural change that may have taken place between the two periods?

MR. GARDINER: No, I did not.

MR. AIKEN: I'm going to describe four regression equations to you. There are two for each of the south and north.

For each region, the first equation is estimated using 1992 through 2011 data, which apparently was used to provide the degree-day forecasts in part (h) of Exhibit J.C-2-3-2, which I believe was an Energy Probe interrogatory. So that is the first equation.

The second equation in each region is the same as the first, with the addition of a dummy variable that has a value of 1 for 1992 through 1997, and zero for the remainder of the years.

So first of all, would you undertake to provide the standard regression statistics -- just like you filed for the volume equations -- for each of these four equations?

In other words, it is the two equations you have used to answer the Energy Probe interrogatory, and then the second two equations are one with the structural dummy variable present in them.

MR. SMITH: Yes, we are prepared to do that.

MR. MILLAR: J1.3.

UNDERTAKING NO. J1.3: TO PROVIDE STANDARD REGRESSION STATISTICS FOR EACH OF FOUR EQUATIONS, AND 2013 DEGREE-DAY FORECAST FOR NORTH AND SOUTH REGIONS USING THE EQUATION WITH DUMMY VARIABLE INCLUDED.

MR. AIKEN: Just before we get off that undertaking, would you also include in that undertaking the 2013 degree-day forecast in that undertaking for each of the north and south using the equation with the dummy variable included in it?

MR. SMITH: Yes, we will do that, as well.

MS. HARE: Just go back to J.1.2. Mr. Millar, can you read me back what the undertaking was?

MR. MILLAR: I only have an annotation here. It was about regression statistics. Perhaps Mr. Aiken could repeat it.

MR. AIKEN: No, Mr. Aiken could not. I've forgotten, as well.

MS. HARE: Okay. Well, that is my concern. I am not sure we know what was the undertaking. Does the panel understand? It was about -- this is what I don't understand.

You filed for southern, 3,599. The question was between 1991 and 2010, what was the equation. But I guess what I am confused about is since 3599 is your number, you would know the equation that you used in the time frame, wouldn't you?

MR. GARDINER: Yes.

customers used a customer–built-up forecast. There's been a lot of focus historically to ensure that the customer's voice was heard in setting their forecast and that it was appropriate.

So that is the manner that we have used to set the top 60 contract customers.

MS. HARE: Mr. Wolnik?

MR. WOLNIK: I think it is important, given they're forecasting zero, that we understand the point in time, the number of hours a day that -- when it would start to kick in.

MR. SMITH: We can verify whether it is at the nine-hour mark or the 12-hour mark. We're happy to do that.

MS. HARE: Yes. That would be helpful.

MR. WOLNIK: Thank you.

MR. MILLAR: J1.8.

UNDERTAKING NO. J1.8: TO CONFIRM START TIME OF OVERRUN CHARGES

MR. WOLNIK: Could you also tell me the amount of overrun revenue that Halton Hills would have collected -- or you would have collected from Halton Hills in 2012, year-to-date?

MS. VAN DER PAELT: 2012-year to date, so end of June, we collected $300,000.

MR. WOLNIK: And you are still forecasting zero for 2013?

MS. VAN DER PAELT: Yes, we are.

MR. WOLNIK: Thank you.

utility. Also included are the de Bever and de Bever with Trend. The remaining two methods that the review considers are the 20-Year Trend and Energy Probe.

15. The Company continues to believe that the measures used in EB-2005-001 are the best to evaluate the suitability of the forecast methods, namely: Accuracy (as represented by Mean Absolute Percent Error ("MAPE") and Root Mean Percent Squared Error ("RMPSE"), Symmetry (as represented by Mean Percent Error ("MPE") and Percent Over-Forecast ("POF") and Stability (as represented by Standard Deviation or "STDEV").

Figure 1
Degree day forecasting methods under consideration

Row 1	Naïve
Row 2	10-Year Moving Average
Row 3	20-Year Moving Average
Row 4	30-Year Moving Average
Row 5	Average of 20-Year Trend and 30-Year Moving Average
Row 6	de Bever
Row 7	de Bever with Trend
Row 8	Energy Probe
Row 9	20-Year Trend

16. Accuracy is concerned with the difference between forecast and actual degree days. MAPE is appealing because of its simplicity. It is the average of the yearly absolute percent errors, where the absolute percent error in any year is the absolute error divided by the actual value. The RMPSE is similar but it squares each percentage error, providing a penalty for large forecasting errors, adding another dimension to the evaluation. For both MAPE and RMPSE, smaller statistics signify better/more desirable results.

17. Symmetry deals with the bias of a particular forecasting method (i.e., whether it consistently forecasts low or high). The MPE is the average of the yearly percent errors, where the percent error is the error divided by the actual value. The closer the MPE is to zero, the less biased is the forecasting approach. The POF measure is equal to the number of over-forecasts divided by the number of years under consideration. The closer this statistic is to fifty percent, the less biased (more symmetrical) the method.

18. Stability relates to the variability of the forecasts over time and is measured by standard deviation. The analysis assigns a high ranking to methods that produce forecasts with a relatively low standard deviation to recognize the notion that steady forecasts are attractive from the perspective of rate stability. However, the Company places half as much importance on Stability (compared to Accuracy and Symmetry) because methods that perform well in this regard are generally poorly equipped to respond to changing weather.

19. Accuracy and symmetry are equally important. Neither ratepayers nor shareholders are well served by a methodology that produces relatively inaccurate results. Furthermore, since no method will be perfectly accurate, placing an importance on symmetry ensures that risks are not unevenly distributed amongst stakeholders. Meanwhile, stability is less important than accuracy and symmetry. Forecasts that are relatively more variable can result in greater rate shock. While rate shock is important, the consequences of inaccurate and/or biased forecasts are more significant.

20. Figure 2 presents the calculation of the error statistics used herein, for reference.

Figure 2
Computation of test statistics

$$MAPE = \frac{\sum_{t=1}^{n} \frac{|Forecast_t - Actual_t|}{Actual_t}}{n} \qquad RMSPE = \sqrt{\frac{\sum_{t=1}^{n} \left(\frac{Forecast_t - Actual_t}{Actual_t}\right)^2}{n}}$$

$$MPE = \frac{\sum_{t=1}^{n} \frac{Forecast_t - Actual_t}{Actual_t}}{n} \qquad POF = \frac{O}{n}$$

$$STDEV = \sqrt{\frac{n\sum_{t=1}^{n} Forecast_t^2 - (\sum_{t=1}^{n} Forecast_t)^2)}{n(n-1)}}$$

O is the number of over-forecasts and *n* is the number of years

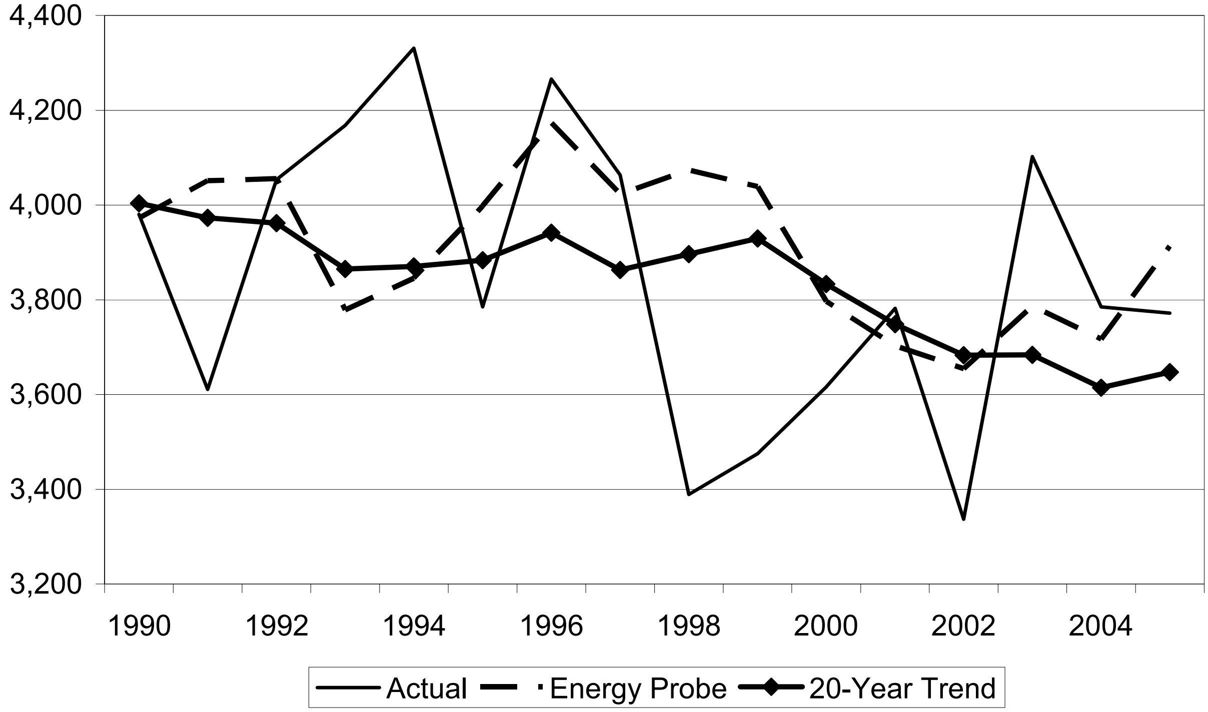
Results

21. Table 5 provides the out-of-sample forecasts that each method generates. For out-of-sample forecasting, the data is divided into an initialization and holdout set. Accordingly, the forecasts are a measure of genuine forecasting ability. Figure 3 graphs the actual degree days along with 20-Year Trend and Energy Probe forecasts from Table 5 (i.e., Columns 2, 10 and 11).

Table 5
Actual and forecast Toronto degree days ('out-of-sample'), 1990 to 2005

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*	*Col. 11*
Fiscal Year	Actual	Naïve	10-yr MA	20-yr MA	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe	20-yr Trend
1990	3,980	4,030	4,111	4,190	4,181	4,092	4,032	3,962	3,973	4,003
1991	3,610	4,030	4,082	4,180	4,178	4,075	4,035	3,972	4,051	3,973
1992	4,053	3,980	4,068	4,158	4,177	4,069	4,035	3,974	4,056	3,962
1993	4,168	3,610	4,000	4,123	4,163	4,014	3,947	3,775	3,778	3,865
1994	4,331	4,053	3,965	4,112	4,166	4,018	3,998	3,843	3,845	3,870
1995	3,785	4,168	4,001	4,114	4,164	4,023	4,046	3,961	3,998	3,883
1996	4,266	4,331	3,998	4,121	4,173	4,057	4,132	4,087	4,174	3,942
1997	4,063	3,785	3,980	4,106	4,153	4,008	4,082	4,008	4,023	3,863
1998	3,389	4,266	4,005	4,115	4,153	4,025	4,142	4,059	4,073	3,896
1999	3,475	4,063	4,032	4,095	4,146	4,038	4,129	4,050	4,039	3,929
2000	3,616	3,389	3,968	4,039	4,116	3,974	3,977	3,873	3,796	3,833
2001	3,782	3,475	3,912	3,997	4,091	3,920	3,859	3,779	3,702	3,748
2002	3,337	3,616	3,876	3,972	4,064	3,874	3,759	3,737	3,655	3,683
2003	4,102	3,782	3,893	3,947	4,046	3,865	3,737	3,739	3,787	3,684
2004	3,785	3,337	3,821	3,893	4,015	3,815	3,570	3,565	3,717	3,614
2005	3,772	4,102	3,814	3,908	4,014	3,831	3,806	3,712	3,913	3,647

Figure 3
20-Year Trend and Energy Probe forecast versus actual degree days



22. Tables 6 through 8 summarize the relative performance of the key methods over three time periods by using the values in Table 5 to compute the error statistics in Figure 2.[4] For each of the five statistics, the methods are assigned a score from one to nine based on their performance (one is best, nine is worst). The scores are summed to arrive at an overall score and rank. Table 6 considers all available years.[5] The Company feels this is the most relevant timeframe as it does not resort

[4] A lower score indicates a better result and is the sum of the rankings in the five individual categories (i.e., MAPE, RMSPE, MPE, POF and STDEV). The values in column 6 of Table 8 are actually the absolute value of the MPE – the end result is not affected.
[5] Years prior to 1990 cannot be legitimately tested due to the large data requirements of the de Bever method and related methods like de Bever with Trend and Energy Probe.

to choosing what amounts to an arbitrary period of time. The 20-year Trend had the highest score.

Table 6
Out-of-sample forecast performance, all available years (1990 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	9.2%	9	11.0%	8	1.4%	2	50%	1	312	9	29	***6***
10-yr MA	7.1%	4	9.1%	4	3.9%	6	69%	6	87	2	22	***3***
20-yr MA	8.1%	7	10.4%	7	6.4%	8	75%	8	95	4	34	***8***
20-yr Trend	**6.8%**	**2**	**8.0%**	**1**	**0.4%**	**1**	**44%**	**3**	**124**	**5**	**12**	***1***
30-yr MA	8.9%	8	11.5%	9	7.9%	9	75%	8	60	1	35	***9***
50/50	7.0%	3	9.1%	3	4.2%	7	69%	6	91	3	22	***3***
de Bever	7.4%	6	9.7%	6	3.5%	5	63%	4	165	8	29	***6***
de Bever with Trend	7.2%	5	9.1%	5	1.6%	3	38%	4	151	6	23	***5***
Energy Probe	**6.8%**	**1**	**8.9%**	**2**	**2.3%**	**4**	**50%**	**1**	**158**	**7**	**15**	***2***

Table 7
Out-of-sample forecast performance, recent ten year period (1996 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	10.2%	8	12.1%	8	2.1%	2	50%	1	362	9	28	***6***
10-yr MA	7.9%	5	10.1%	4	5.2%	6	70%	5	78	2	22	***4***
20-yr MA	9.0%	7	11.6%	7	7.6%	8	80%	8	88	3	33	***8***
20-yr Trend	**7.6%**	**2**	**8.7%**	**1**	**1.3%**	**1**	**40%**	**3**	**123**	**5**	**12**	***1***
30-yr MA	10.4%	9	13.1%	9	9.7%	9	80%	8	60	1	36	***9***
50/50	7.9%	4	10.2%	5	5.5%	7	70%	5	91	4	25	***5***
de Bever	8.5%	6	11.1%	6	4.9%	5	70%	5	202	8	30	***7***
de Bever with Trend	7.7%	3	10.0%	3	3.4%	3	40%	3	181	6	18	***3***
Energy Probe	**6.9%**	**1**	**9.3%**	**2**	**4.0%**	**4**	**50%**	**1**	**181**	**7**	**15**	***2***

23. Again referring to Table 6, both the 20-Year Trend and Energy Probe do about as well as one another with respect to the MAPE statistic; however the RMSPE is significantly lower for the 20-Year Trend, meaning that the 20-Year Trend has produced fewer large errors. For instance, the Energy Probe method produces an error of nearly 700 degree days in 1998 and over 550 the following year. For Accuracy as a whole, the 30-Year Moving Average method is the least accurate. It

is unable to adjust to the decreasing degree days and consequently produces the largest errors.

Table 8
Out-of-sample forecast performance, recent five year period (2001 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	9.0%	9	9.1%	7	2.1%	5	40%	1	296	9	31	***8***
10-yr MA	5.4%	2	7.8%	5	3.3%	7	80%	4	43	4	22	***6***
20-yr MA	7.0%	7	9.3%	8	5.5%	8	80%	4	43	3	30	***7***
20-yr Trend	**5.9%**	**5**	**7.0%**	**2**	**1.7%**	**4**	**20%**	**4**	**50**	**5**	**20**	***2***
30-yr MA	8.8%	8	11.2%	9	8.2%	9	80%	4	33	1	31	***8***
50/50	5.6%	3	7.9%	6	3.3%	6	80%	4	41	2	21	***5***
de Bever	6.0%	6	7.4%	4	0.2%	1	60%	1	109	8	20	***2***
de Bever with Trend	5.7%	4	7.2%	3	0.9%	3	20%	4	83	6	20	***2***
Energy Probe	**5.0%**	**1**	**5.9%**	**1**	**0.3%**	**2**	**40%**	**1**	**100**	**7**	**12**	***1***

24. The 20-Year Trend also produces vastly superior results where symmetry is concerned for the 1990 to 2005 period, yielding an MPE of a mere 0.4 percent. Meanwhile, the Energy Probe technique has a clear over-forecasting bias given the MPE of 2.3 percent. On average the Energy Probe forecast is too high by 67 degree days compared to seven too low for the 20-Year Trend. In terms of POF, the two methods score roughly the same, although the 20-Year Trend over-forecasts seven out of 16 times, while the Energy Probe over-forecasts on eight out of 16 occasions. For Symmetry in total, the 30-Year Moving Average is most deficient, consistently over-forecasting over the course of the relevant period.

25. Still referring to Table 6, the standard deviation of the 20-Year Trend forecasts is lower than the comparable value for the Energy Probe forecasts, meaning the 20-Year Trend is relatively more stable. All else being equal then, the Energy Probe method would have subjected ratepayers to relatively more volatility in rates in recent years.

EB-2006-0034

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

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

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

JULY 5, 2007

FORECAST OF DEGREE DAYS

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

Issue 2.3 reads "Is the forecast of degree days appropriate?"

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

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

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

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

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

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

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

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

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

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

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

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

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

Board Findings

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

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

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

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

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

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

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

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

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

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

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

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

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

from one year's forecast to the next is increasing over time. The increase in variation of the historical weather statistics is a direct contributing factor to increasing instability. For stability, a smaller standard deviation means that the method provides a more stable estimate because the difference between the forecast HDDs in two consecutive years is less significant.

Table 1
Weather Normal Forecast Estimate vs. Actual Weather

Weather normal forecast estimate versus actual annual level
25 Observations: estimates for 1985 to 2010 inclusive

	30 yr Avg.	20 Yr DT	55:45 Blend
Root Mean Square Error: RMSE	375	**269**	306
Average Variance from Actual	276	**56**	177
Std Deviation of Variance	259	269	255
Mean Percent Error	-7.7%	**-1.9%**	-5.1%

The statistical metrics in bold font in the table above show that the 20-year declining trend method (“20 Yr DT”) is the superior weather normalization method. This is indicated by three of the four statistical metrics that compare the 20-year declining trend method to the current blended weather normal method and the 30-year average method used by Union before 2004. The RMSE average variance from actual and the mean percent error are accuracy measurements. The standard deviation of the variance is a stability measurement. The 20-year declining trend is a simple and sustainable weather normalization method.

UNION GAS LIMITED

Undertaking of Mr. Aiken
To Mr. Gardiner

Please provide equation and regression statistics for the forecast of 3,599 degree days for the south region.

Filed in 2013 REGN DATA FILE_Apr30 2012 (Content Sheet Added).xlsx
in Tab 4 Actual Weather vs Normal

SUMMARY OUTPUT: SOUTHERN FRANCHISE AREA 1991 TO 2010 TREND FOR 2013

Regression Statistics	
Multiple R	33.2%
R Square	11.0%
Adjusted R Square	6.1%
Standard Error	251.00
Observations	20

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	140,312	140,312	2.227	0.153
Residual	18	1,133,988	62,999		
Total	19	1,274,300			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	32,839.3	19,471.415	1.687	11%	- 8,069	73,747
Time	- 14.5	9.733	- 1.492	15%	- 34.974	5.923

UNION GAS LIMITED

Undertaking of Mr. Aiken
To Mr. Gardiner

Please provide standard regression statistics for each of four equations, and 2013 degree-day forecast for North and South regions using the equation with dummy variable included.

The results for the four requested regressions are contained in Attachments 1-4. The time period for estimation is 1992 to 2011, 20 years.

Two models are estimated for Union South and Union North, respectively:

- Model 1 regresses actual heating degree days against time and a dummy variable for the period 1998 to 2011.
- Model 2 is the 20-Year Declining Trend method.

In Union's view, the inclusion of a dummy variable is not appropriate because inclusion of the dummy variable would necessitate the annual respecification of the degree day trend equation and be subjective. For example, starting the dummy variable in 1999 would result in a weather normal not materially different (1%) from the 20-year trend, while starting in 1998 would because 2012 is warmer than normal. Consideration would also have to be given to setting the dummy variable for 2012 to 1 or even 2 from 0.

SUMMARY OUTPUT: Southern HDD - Time & dummy variables for 1998 to 2011

Time Span: 1992 to 2011	
Regression Statistics	
Multiple R	75%
R Square	56%
Adjusted R Square	51%
Standard Error	179.93
Observations	20

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	708,723.71	354,361.85	10.95	0.00
Residual	17	550,352.11	32,373.65		
Total	19	1,259,075.82			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	- 30,764.03	22,927.10	- 1.34	0.20	- 79,135.98	17,607.92
X Time	17.46	11.50	1.52	0.15	- 6.79	41.71
X Dummy 98-11	- 563.12	144.64	- 3.89	0.00	- 868.29	- 257.95

RESIDUAL OUTPUT

Observation	*Actual HDD*	*Predicted HDD*	*Residuals*
1992	4031	4012	19
1993	4105	4030	75
1994	4055	4047	8
1995	3987	4065	-78
1996	4153	4082	70
1997	4005	4099	-94
1998	3175	3554	-379
1999	3554	3571	-18
2000	3792	3589	203
2001	3469	3606	-138
2002	3652	3624	28
2003	3988	3641	347
2004	3807	3659	148
2005	3838	3676	161
2006	3407	3693	-286
2007	3700	3711	-11
2008	3869	3728	141
2009	3824	3746	78
2010	3574	3763	-190
2011	3695	3781	-86
2012		3798	
2013		3816	

forecast is highlighted

SUMMARY OUTPUT: Southern HDD - 20 Year Trend

Time Span: 1992 to 2011

Regression Statistics	
Multiple R	42%
R Square	17%
Adjusted R Square	13%
Standard Error	240.49
Observations	20

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	218,044.26	218,044.26	3.77	0.07
Residual	18	1,041,031.56	57,835.09		
Total	19	1,259,075.82			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	40,026.27	18,665.61	2.14	0.05	811.27	79,241.27
X Time	- 18.11	9.33	- 1.94	0.07	- 37.70	1.49

RESIDUAL OUTPUT

Observation	*Actual HDD*	*Predicted HDD*	*Residuals*
1992	4,031	3,956	75
1993	4,105	3,938	167
1994	4,055	3,920	135
1995	3,987	3,902	85
1996	4,153	3,883	269
1997	4,005	3,865	140
1998	3,175	3,847	-672
1999	3,554	3,829	-276
2000	3,792	3,811	-19
2001	3,469	3,793	-324
2002	3,652	3,775	-123
2003	3,988	3,757	231
2004	3,807	3,739	68
2005	3,838	3,720	117
2006	3,407	3,702	-295
2007	3,700	3,684	16
2008	3,869	3,666	203
2009	3,824	3,648	176
2010	3,574	3,630	-56
2011	3,695	3,612	83
2012		3,594	
2013		3,576	

forecast is highlighted

SUMMARY OUTPUT: Northern HDD - Time & dummy variables for 1998 to 2011

Time Span: 1992 to 2011

Regression Statistics	
Multiple R	78%
R Square	60%
Adjusted R Square	56%
Standard Error	234.89
Observations	20

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	1,419,229.11	709,614.55	12.86	0.00
Residual	17	937,980.83	55,175.34		
Total	19	2,357,209.94			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	4,784.81	29,931.31	0.16	0.87	- 58,364.73	67,934.36
X Time	0.32	15.01	0.02	0.98	- 31.34	31.98
X Dummy 98-11	- 584.49	188.83	- 3.10	0.01	- 982.89	- 186.09

RESIDUAL OUTPUT

Observation	*Actual HDD*	*Predicted HDD*	*Residuals*
1992	5,489	5,422	67
1993	5,460	5,422	38
1994	5,294	5,422	-129
1995	5,358	5,423	-65
1996	5,550	5,423	127
1997	5,384	5,423	-39
1998	4,457	4,839	-382
1999	4,754	4,839	-85
2000	5,065	4,840	225
2001	4,613	4,840	-227
2002	5,007	4,840	166
2003	5,147	4,841	306
2004	5,216	4,841	375
2005	4,866	4,841	24
2006	4,473	4,842	-369
2007	4,888	4,842	46
2008	5,040	4,842	197
2009	5,049	4,843	206
2010	4,462	4,843	-381
2011	4,741	4,843	-102
2012		4,844	
2013		4,844	

forecast is highlighted

SUMMARY OUTPUT: Northern HDD - 20 Year Trend

Time Span: 1992 to 2011

Regression Statistics	
Multiple R	61%
R Square	38%
Adjusted R Square	34%
Standard Error	285.44
Observations	20

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	890,597.4	890,597.4	10.9	0.0
Residual	18	1,466,612.5	81,478.5		
Total	19	2,357,209.9			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	78,261.81	22,154.81	3.53	0.00	31,716.28	124,807.33
X Time	- 36.60	11.07	- 3.31	0.00	- 59.85	- 13.34

RESIDUAL OUTPUT

Observation	*Actual HDD*	*Predicted Y*	*Residuals*
1992	5,489	5,363	126
1993	5,460	5,327	134
1994	5,294	5,290	4
1995	5,358	5,253	104
1996	5,550	5,217	333
1997	5,384	5,180	204
1998	4,457	5,144	-686
1999	4,754	5,107	-353
2000	5,065	5,070	-5
2001	4,613	5,034	-421
2002	5,007	4,997	9
2003	5,147	4,961	186
2004	5,216	4,924	292
2005	4,866	4,887	-22
2006	4,473	4,851	-378
2007	4,888	4,814	74
2008	5,040	4,778	262
2009	5,049	4,741	308
2010	4,462	4,704	-243
2011	4,741	4,668	73
2012		4,631	
2013		4,595	

forecast is highlighted

UNION GAS LIMITED

Undertaking of Mr. Aiken
To Mr. Gardiner

Please provide 2013 forecast for commercial old Rate M2 and the industrial Rate M2 consistent with table on page 2 of LPMA compendium.

Normalized Average Consumption by Rate $ Service Class (m^3 / year)
All NACs weather normalized according to the 2013 20Year Declining Trend weather normal

Line		Residential		Commercial			Industrial		
No.	Year	Rate M2	Rate 01	Old Rate M2	Rate 01	Rate 10	Rate M2	Rate 10	Rate L.I.B. 10
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	1991	2,940	3,029	18,696	10,471	104,964	73,495	273,591	2,501,299
2	1992	2,883	3,001	19,003	10,229	98,717	70,265	256,959	2,708,373
3	1993	2,830	2,914	18,416	10,000	98,246	74,784	269,677	2,933,314
4	1994	2,753	2,876	17,670	9,716	102,248	74,559	287,596	1,101,389
5	1995	2,782	2,810	17,799	9,510	104,512	73,905	270,517	1,315,339
6	1996	2,792	2,751	18,438	9,480	102,112	75,488	288,617	1,223,738
7	1997	2,760	2,741	18,222	9,454	99,958	78,169	242,400	968,749
8	1998	2,725	2,624	17,533	8,196	94,729	78,078	158,054	830,471
9	1999	2,689	2,646	17,572	7,959	87,960	82,876	178,165	982,337
10	2000	2,701	2,762	17,277	9,102	101,632	74,280	194,437	998,704
11	2001	2,598	2,575	17,074	8,794	91,677	82,091	204,217	835,453
12	2002	2,585	2,573	17,126	8,626	95,897	84,076	231,508	834,090
13	2003	2,535	2,584	17,052	8,693	91,545	83,026	267,897	877,057
14	2004	2,464	2,468	16,649	8,320	90,208	78,036	224,118	949,805
15	2005	2,386	2,417	16,133	8,126	88,468	82,054	245,088	908,018
16	2006	2,407	2,396	16,608	7,695	87,033	79,135	220,599	881,745
17	2007	2,392	2,384	16,324	7,949	91,365	81,102	253,843	889,643
18	2008	2,362	2,379	16,851	8,465	106,559	80,445	280,730	914,299
19	2009	2,290	2,328	16,526	8,350	105,374	75,122	310,569	872,901
20	2010	2,284	2,268	16,182	8,314	111,416	67,057	310,317	938,636
21	2011	2,264	2,269	17,213	8,580	124,714	73,561	372,911	1,074,867
22	2012	2,199	2,211	16,273	8,257	119,987	76,344	335,572	1,068,018
23	2013	2,148	2,160	16,077	8,153	120,442	76,058	336,471	1,108,624

forecast estimates

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Ms. Van Der Paelt

Please provide overrun forecast for all markets.

Market ($Millions)	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
Power	0.0	0.0	0.0	0.3	0.6	0.0	0.0
Steel/Chem/Ref	0.3	0.4	0.4	0.3	0.4	0.0	0.0
LCI/Key	1.6	1.1	1.0	1.1	1.2	0.5	0.6
Greenhouse	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Grand Total	2.1	1.7	1.5	1.8	2.4	0.5	0.6

UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

Ref: Exhibit C1, Tab 3

For the period 2007-2013 please provide a schedule setting out forecast and actual (where available) S&T revenue, including all components.

Response:

Please see Attachment 1.

UNION GAS LIMITED
Summary Revenue from Storage and Transportation of Gas
Years Ending December 31

Line No.	Particulars ($000's)	Board Approved 2007	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Transportation								
1	M12 Transportation (1)	120,667	121,812	133,833	138,681	142,421	138,273	133,972	121,109
2	M12-X Transportation	-	-	-	-	-	1,477	5,942	13,499
3	C1 Long-term Transportation	2,900	2,093	5,790	6,642	6,288	7,570	6,554	5,246
4	C1 Short-term Transportation and Exchanges	4,000	9,030	23,266	29,781	32,554	44,228	32,186	20,186
5	C1 Rebate Program	(2,178)	(1,874)	-	-	-	-	-	-
6	M13 Transportation	864	649	529	462	386	323	366	367
7	M16 Transportation	553	240	474	609	610	642	581	581
8	Other S&T Revenue	895	975	1,193	1,150	1,072	1,092	1,067	1,067
9	Total Transportation Revenue	127,701	132,925	165,085	177,325	183,331	193,605	180,668	162,055
	Storage								
10	Short-term Storage Services	13,887	16,211	15,777	17,745	14,886	9,036	6,590	8,988
11	Off-Peak Storage/Balancing/Loan Services (2)	4,075	8,050	7,550	11,169	6,001	1,928	2,500	2,500
12	Total Storage Revenue	17,962	24,261	23,327	28,914	20,887	10,964	9,090	11,488
13	Total S&T Revenue	145,663	157,186	188,412	206,239	204,218	204,569	189,758	173,543

Note:
(1) Includes M12 Transportation overrun.
(2) Includes Enbridge LBA.

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Aiken

Please update table from JT1.13 to reflect year-to-date June actual and forecasts, and break out FT RAM credits included in line 4 as a separate line item.

Please see the Attachment.

UNION GAS LIMITED
Summary Revenue from Storage and Transportation of Gas

Line No.	Particulars ($000's)	Actual 2012 (June YTD) (a)	Forecast 2012 (June YTD) (b)	Difference (c)
	Transportation			
1	M12 Transportation	67,669	67,716	(47)
2	M12-X Transportation	2,208	2,215	(7)
3	C1 Long-term Transportation	3,643	3,391	252
4	C1 Short-term Transportation	6,017	6,467	(450)
5	Exchanges - Base	6,628	4,000	2,628
6	Exchanges - Net RAM	19,859	6,997	12,862
7	C1 Rebate Program	-	-	-
8	M13 Transportation	152	182	(30)
9	M16 Transportation	287	312	(25)
10	Other S&T Revenue	513	533	(20)
11	Total Transportation Revenue	106,976	91,813	15,163
	Storage			
12	Short-term Storage Services	5,834	3,125	2,709
13	Off-Peak Storage/Balancing/Loan Services	1,259	1,250	9
14	Total Storage Revenue	7,093	4,375	2,718
15	Total S&T Revenue	114,069	96,188	17,881

In 2010, there was one customer who utilized $0.546 million of M12 transportation overrun. In 2011, this customer used $0.017 of M12 transportation overrun. Union is not forecasting any M12 transportation overrun in 2012 and 2013.

2013 Forecast vs. 2012 Forecast Variance

In 2013, the M12 transportation revenue is forecast to decline by of $5.3 million. This is largely due to:

i. A 10 month (January – October) impact of the reduction in Dawn-Kirkwall demand of 375,188 GJ/d beginning on November 1, 2012, decreasing revenue by $7.5 million;
ii. A 2 month (November – December) impact of the further reduction of Dawn-Kirkwall and Dawn-Parkway demands of 353,198 GJ/d beginning November 1, 2013, decreasing revenue by $1.4 million;
iii. A full year impact of new Dawn-Parkway and Kirkwall-Parkway sales which commenced in May and November 2012 and the 2 month impact of a Kirkwall-Parkway sale of 174,752 GJ/d commencing November 1, 2013. These changes increase revenue by $2.3 million;
iv. A full year impact of the M12X transportation service, which started in 2012, increasing revenue by $1.7 million. This impact is partially offset by a reduction in Parkway to Dawn and Parkway to Kirkwall C1 Long-term Transportation revenue as discussed later in this evidence; and,
v. A net reduction in F24T revenue of $0.3 million.

Impacts of M12 Transportation Turnback

As noted above, Union has received notice from customers for significant turnback of M12 transportation contracts in 2011 and 2012, and is forecasting further turnback in 2013. A summary of the M12 transportation turnback can be found on Schedule 3.

In 2011, all of the turned back Dawn-Kirkwall capacity of 317,000 GJ/d was resold; 179,661 GJ/d of Dawn-Parkway capacity and 31,746 GJ/d of Dawn-Kirkwall capacity was sold with a November 1, 2011 start date. A further 122,950 GJ/d of Dawn-Parkway capacity was sold with 2012 start dates.

In 2012, a further 375,188 GJ/d of Dawn-Kirkwall capacity has been turned back. Based on Open Seasons held in 2010 and 2011, Union was able to sell 11,000 GJ/d of the available Dawn-Parkway capacity. In addition, approximately 200,000 GJ/d was used to reduce winter peaking service requirements. As a result, Union has no forecast winter peaking service requirements in 2012 or 2013.

In 2013, a further 286,198 GJ/d in Dawn-Kirkwall capacity and 67,000 GJ/d of Dawn-Parkway capacity is forecast to be turned back. Union does not forecast any new sales of Dawn-Parkway or Dawn-Kirkwall capacity in 2013.

For 2012 and 2013, Union was able to provide Kirkwall-Parkway service of 88,497 GJ/d, commencing November 1, 2012, and an incremental 174,752 GJ/d commencing November 1, 2013.

Other Long-term Transportation

There are three components that comprise the Other Long-term Transportation revenue forecast: C1 Long-term Transportation; M13 (Local Production); and M16 (Storage Transportation Service). Actual and forecast revenues for these services are shown in Table 2.

Table 2

Other Long-term Transportation Revenue

Revenue ($ Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
C1 Long-term Transportation	$6.3	$7.6	$6.6	$5.2
M13 Transportation	0.4	0.3	0.4	0.4
M16 Transportation	0.6	0.6	0.6	0.6
Total	$7.3	$8.5	$7.6	$6.2

The change in revenue between 2010 Actual and the 2013 Forecast is entirely due to C1 Long-term Transportation demand. The decline in C1 Long-term Transportation revenue since 2011 is due to changes in market dynamics and gas flows affecting the Dawn-Parkway and Ojibway systems. Specific changes are detailed below and provided in Schedules 4 and 5.

i. In 2011, C1 Long-term Transportation revenue is higher than 2010 by $1.3 million. The largest component of this change is a Dawn-Dawn (TCPL) contract for 500,000 GJ/d which commenced November 1, 2010, creating a 10 month (January to October) variance of $1.1 million. There is also a full year impact of nearly $0.5 million related to contract increases of 36,212 GJ/d for Ojibway-Dawn capacity which commenced in October and November, 2010. This is offset by a contract non-renewal for 36,927 GJ/d on the Ojibway-Dawn path, effective April 1, 2011;

ii. In 2011, Parkway-Kirkwall C1 Long-term Transportation demand of 128,316 GJ/d (September 1, 2011 start date) was converted to the new bi-directional M12X transportation service, reducing C1 Long-term Transportation revenue by $0.3 million. In 2012, Parkway-Dawn C1 Long-term Transportation demand of 200,000 GJ/d (November 1, 2012 start date) was also converted, reducing C1 Long-term Transportation revenue by approximately $0.8 million in 2012. Offsetting demands and revenues for the M12X transportation service in both 2011 and 2012 are reflected in M12 Transportation Revenue, described earlier; and,

iii. In 2013, there is a 10 month (January to October) impact of the M12X conversion, reducing revenue by $1.1 million. There is a further reduction in Parkway-Dawn C1 Long-term Transportation demand of 54,357 GJ/d (April 1, 2013 start date), due to contract expiries and reductions, resulting in a decline in revenue of $0.3 million.

Other S&T Revenue

The final component of the Long-term Transportation revenue forecast is Other S&T Revenue. This is comprised of revenue earned from name changes, Ontario Producers and other miscellaneous services. The revenue for these services has been constant at $1.1 million in 2010 and 2011. The forecast for 2012 and 2013 is $1.1 million.

2/ SHORT-TERM TRANSPORTATION AND EXCHANGES REVENUE FORECAST

The short-term transportation and exchanges revenue forecast is $32.2 million for 2012, and $20.2 million for 2013. Factors which influence this forecast are customer demands, market prices, locational basis spreads and weather. The forecast assumes normal weather, and it also assumes there will be no incremental transportation capacity built downstream of Parkway beyond the proposed TCPL expansions for 2012 and 2013.

This forecast is made up of two main components: transportation and exchanges.

Transportation

The transportation component of the transactional forecast is comprised of short-term firm and interruptible transportation on Union's Dawn-Parkway system, the Ojibway system, and St. Clair/Bluewater system. Actual and forecast revenues for these services on the three systems are shown in Table 3.

Table 3

Short-term Transportation Revenue

Revenue - $Million's	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
Dawn-Parkway system	$9.3	$8.0	$8.7	$8.7
Ojibway system	2.6	1.0	0.6	0.6
St. Clair/Bluewater system	0.9	3.5	1.8	1.8
TOTAL	$12.8	$12.5	$11.1	$11.1

The decline in revenues for Dawn-Parkway short-term transportation since 2010 reflects the reduction in Dawn-Parkway values resulting from insufficient take-away capacity on TCPL downstream of Parkway. More detail regarding this can be found at Exhibit A2, Tab 1, Schedule 1 which discusses, among other things, the changes in gas supply dynamics, the impact of the changes on Union's Dawn to Parkway system and the impact of TCPL's capacity constraint between Parkway and TCPL's connection at Maple.

The significant reduction in revenue on the Ojibway path reflects the reduction in market spreads seen in 2011.

Changes in the Transportation Market

Since 2007, there have been significant changes in the North American gas market. These changes are described at Exhibit A2, Tab 1, Schedule 1 and Schedule 4.

There has been a significant reduction in load factors on TCPL long-haul service, resulting in increases in TCPL tolls. In order to mitigate this trend, TCPL introduced the Firm Transportation Risk Alleviation Mechanism (“FT RAM”) program. This program gives firm shippers of long-haul capacity (or short-haul capacity linked to long-haul capacity) credits for any capacity left unutilized. These credits can then be spent, in the same month upon which they are earned, on any interruptible service on TCPL’s system. The program was designed to encourage shippers to remain contracted on TCPL’s system.

On September 1, 2011, TCPL filed evidence with the National Energy Board (“NEB”) aimed at redesigning their overall framework. Included in TCPL’s proposal was the elimination of the FT RAM program.

The 2012 forecast assumes the TCPL FT RAM program will be eliminated on November 1, 2012. A full year impact of the FT RAM program being discontinued is reflected in 2013.

<u>Exchanges</u>

Exchange revenue is comprised of activity using Union’s upstream transportation capacity to provide exchange services to third-parties. It also includes net revenue generated from pipe releases or revenue from TCPL’s FT RAM program. Actual and forecast revenue for exchanges are shown in Table 4.

Table 4
Exchange Revenue

Year	$ Millions
2006	2.6
2007	3.4
2008	11.6
2009	20.5
2010	19.7
2011 Actual	31.7
2012 Forecast	21.1
2013 Forecast	9.1

The single biggest factor contributing to growth in exchange revenue was the utilization of the TCPL FT RAM program starting in 2008. Full year impacts of this program are seen in 2009 and 2010. Union's 2011 actual revenue is primarily supported by TCPL's FT RAM program, but also includes activity related to colder-than-normal weather, TCPL outages, and system outages downstream of Parkway. All of these factors resulted in price spikes that are not forecast to reoccur.

It is also expected that during the forecast period, the increase in shale production will continue to put downward pressure on market spreads for exchange paths, thus reducing value of services to points such as Iroquois. This is described at Exhibit A, Tab 2, Schedule 1.

The 2013 forecast of $9.1 million exceeds the actual revenues earned in years prior to the TCPL FT RAM program optimization. As noted earlier, TCPL's FT RAM program is expected to be terminated in 2012.

3/ SHORT-TERM STORAGE & BALANCING

Union's forecast for short-term storage and balancing is $9.1 million in 2012 and $11.5 million in 2013. This forecast is made up of two components: peak short-term storage, and off-peak storage, balancing and loans.

Changes in Short-term Storage Market

Since 2007, there has been a steady decline in short-term storage prices, with the most significant reductions seen since spring, 2010. These storage price reductions reflect a declining spread between summer and winter gas prices. The main drivers for this declining spread are:

i. Increased summer values as a result of higher demands in the power sector;
ii. Lower winter values as a result of higher supplies from increased Marcellus shale production; and,
iii. Lower winter values as a result of lower demands resulting from an overall sluggish economy in the U.S., as well as energy efficiencies.

The decline in storage spreads is exemplified by the reduction in the actual price of short-term peak storage space relative to price included in approved rates. In 2011, 10.1 PJ of short-term

UNION GAS LIMITED

Undertaking of Mr. Wood
To Mr. Quinn

Please confirm whether incremental M12 and M12X contracts for 2013/2014 are in the 2013 forecast.

Union has updated the available capacity on the Dawn-Parkway system at J7.4 to 211,201 GJ/d. This update includes all changes to the M12, M12X and C1 long-term firm contracts since the forecast was originally filed. These changes include a new M12 Kirkwall-Parkway contract, small quantity changes to two Dawn-Parkway contracts, and actual turnback of M12 contract effective November 1, 2013. Details regarding the actual turnback relative to the forecast is summarized at J.C-4-2-1a.

The impact of any changes to the M12, M12X, and C1 long-term firm contracts since the forecast was completed would be an increase to S&T revenue of approximately $280,000 in 2013. Union is not proposing to update the 2013 S&T revenue to reflect this increase.

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Aiken

Please update chart at J.DV-2-2-1, Attachment 1, to exclude impact of FT RAM.

Please see the Attachment.

Union Gas Limited
Summary of Transportation and Exchange Services
For the Years Ending December 31

Line No.	Particulars ($000's)		Actual 2010 (a)	Actual 2011 (b)	Forecast 2012 (c)	Forecast 2013 (d)
	Transportation and Exchange Services Previously Account #179-69					
1	Net Revenue (Excluding FT-RAM Revenue)	(1)	21,400	22,245	17,986	20,186
2	Less: Costs (Excluding Costs Applicable to FT-RAM Revenue)		11,592	7,792	7,671	6,448
3	Gross Margin		9,808	14,453	10,315	13,738
4	Less: Board Approved Margin in Rates		6,883	6,883	6,883	13,738
5	Hypothetical Deferred Margin	(2)	2,925	7,570	3,432	-

Note:
(1) Revenue less direct costs to provide exchange services.
(2) Margin would have been subject to earnings sharing.

UNION GAS LIMITED

Undertaking of Mr. Isherwood
To Mr. Thompson

Please provide a forecast for the balance of 2012, assuming FT RAM continues for the balance of the year.

As filed in J6.3, year-to-date June exchange revenue related to RAM is $19.9 million. Union estimates RAM-related activity for the balance of 2012 to be an additional $17.9 million, for an annual total of $37.8 million. This includes $3.6 million of the estimated impact of RAM continuing for November and December as filed in J.C-4-7-9 c).

UNION GAS LIMITED
Other Revenue
Board-Approved 2007 - 2013

Line No.	Particulars ($000's)	Board-Approved 2007 (a)	Actual 2007 (b)	Actual 2008 (c)	Actual 2009 (d)	Actual 2010 (e)	Actual 2011 (f)	Forecast 2012 (g)	Forecast 2013 (h)	
1	Delayed payment charges	7,231	7,424	7,876	8,680	5,833	6,770	6,403	6,467	/u
2	Account opening charges	5,858	7,332	6,851	6,894	6,579	6,586	7,000	7,000	/u
3	Billing revenue	9,041	9,677	9,059	8,479	7,369	6,013	6,509	6,387	/u
4	Mid market transactions	2,000	3,684	2,070	2,303	2,244	1,298	2,000	2,000	/u
5	Other operating revenue	304	1,732	432	357	1,479	2,413	1,250	1,278	/u
6	Total other revenue	24,434	29,849	26,288	26,713	23,504	23,080	23,162	23,132	/u

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit A1, Tab 13, Schedule 2

a) The evidence indicates that Union is not proposing any changes to the fee schedule shown. When has Union last reviewed the costs associated with each of the charges shown to ensure that these costs are being recovered through the fees shown? Please provide the results of this last review for each of the charges shown.

b) Please provide table at the same level of detail as the charges shown that shows the total actual revenue generated for each of the charges for 2010 and 2011, along with a forecast for 2012 (including as many months of actual data as are available) and the forecast for 2013.

Response:

a) Union's non-energy charges are based on an examination of the costs required to provide the services. Union reviews these costs on an annual basis. Since Board approval is required to change these charges, Union would file the necessary cost data to support any proposed changes.

b) Please see Attachment 1.

These charges are forecast at a macro level within the Other Revenue forecast. Please see Exhibit C1, Summary Schedule 6.

The variance to forecast for January – March 2012 is:

- $25,000 increase related to Account opening charges.
- $413,000 reduction related to Billing revenues, ABCT charges (not shown in Attachment 1) account for approximately 50% of this variance.

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

UNION'S 2013 RATE REBASING APPLICATION: STORAGE AND TRANSPORTATION ISSUES

EB-2011-0210

Prepared for

Canadian Manufacturers & Exporters (CME)
Consumers Council of Canada (CCC)
The Corporation of the City of Kitchener (CCK)
Federation of Rental-housing Providers of Ontario (FRPO)

By

John A. Rosenkranz

May 16, 2012

Utility Storage Space should be included in the Excess Utility Cross Charge, and the utility revenue requirement should be reduced by $343,500.

Union's Use of Utility Transmission Assets for Non-Utility Storage

In the NGEIR Decision, the Board recognized that because Union owns and operates an integrated gas distribution, transmission and storage business, one consequence of its forbearance decision is the need to ensure access to Union's transportation system on a non-discriminatory basis.[6] To prevent discriminatory treatment and create a level playing field, affiliated storage operators and Union's own non-utility storage business should have the same access to Union transmission assets, and pay the same costs, as a non-affiliated storage operator.

In EB-2011-0038, intervenors and Board Staff raised questions about Union's use of transportation assets by its non-utility storage business. In its Decision, the Board noted that Union had agreed that if a non-utility storage asset is connected to Dawn through a transmission asset, there should be a charge.[7] More generally, however, the Board found

> there is not enough evidence in this proceeding to make a determination regarding the use of transportation services for non-utility storage operations. The Board directs Union to include sufficient evidence on this issue in its rebasing application for the Board to make a determination at that time.[8]

Recommendation 6: When utility transmission assets are used for a non-utility storage pool within Union's service area, Union should credit the utility revenue requirement using the M16 firm service rate.

In this proceeding, Union addresses one situation where utility transmission assets are used to connect a new non-utility storage pool with Dawn. Specifically, Union proposes to credit the utility revenue requirement by $60,277 for the value of transportation service used for Heritage storage pool, which is connected to Union's Sarnia Industrial Line. This credit is based on the proposed M16 service interruptible transportation rate and an annual storage injection and withdrawal quantity of 900,000 GJ.[9]

[6] NGEIR Decision (EB-2005-0551), p. 85.
[7] EB-2011-0038 Decision and Order, p. 16.
[8] EB-2011-0038 Decision and Order, p. 18.
[9] Exhibit H3, Tab 8, Schedule 14.

According to Union, the M16 interruptible rate is appropriate in this case because "Heritage Storage pool transports gas to and from Dawn on an interruptible basis only".[10] However, unless Union can demonstrate that withdrawals from the Heritage Storage pool are actually subject to curtailment, Union should provide a credit to the utility revenue requirement that is based on the quality of the service being provided, using the M16 firm transportation rate and the Heritage Storage pool's maximum daily withdrawal capacity of 319 10^3m^3/day.[11]

Recommendation 7: When utility transmission assets are used to transport gas between an off-system third party storage service and Dawn, utility ratepayers should receive the same value for the capacity that they would receive from an unaffiliated storage operator.

Union's application does not address the situation where owned or contracted transmission capacity that is paid for by utility ratepayers is used by Union's non-utility storage business to transport natural gas between a third-party storage service and Dawn. This situation specifically applies to Union's contracts for Michigan storage. For example, Union previously reported that it entered into a long-term contract with Michigan Consolidated Gas Company (MichCon) for 2.1 PJ of firm storage service. Gas withdrawn from this Michigan storage service was to have been transported between Michigan and Dawn using firm transportation capacity on the Dawn Gateway Pipeline. If Dawn Gateway did not go forward, Union said that it would continue to use "the traditional MichCon/Union Gas path between MichCon and Dawn".[12] Since Dawn Gateway has been cancelled, Union ratepayers are entitled to know whether Union transmission capacity, or upstream third-party transportation capacity under contract to Union's utility business, is being used to transport MichCon storage withdrawals to Dawn on behalf of Union's non-utility storage operation, and if so, how utility ratepayers will be compensated. Under these circumstances, Union should be required to provide evidence about its third party storage contracts and associated transportation arrangements[13].

[10] Exhibit J.C-6-10-1
[11] "During withdrawal operations, gas will flow from the Heritage Pool to the Sarnia Industrial Line Station at a design withdrawal rate of 319 10^3m^3/day." (EB-2008-0405 Application, p. 16)
[12] EB-2011-0038, 7/26/2011 Technical Conference Transcript, p. 52.
[13] "Other third party storage contracts are part of Union's unregulated business and are not relevant to Union's 2013 regulated rates." (Exhibit J.C-6-10-5)

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Mr. Isherwood

Please provide the impact on revenue requirement if interruptible contracts for services were firm.

If the M16 interruptible contracts were firm, net transportation revenue would increase by approximately $0.8 million per year, reducing the revenue deficiency by the same amount. M16 revenues would increase by $0.9 million. However, the firm M16 transportation contracts would reduce the firm capacity available as C1 St. Clair to Dawn transportation and result in reduced revenues. The reduction in C1 St. Clair to Dawn revenue would be $0.1 million.

Firm M16 service is not available or practical for all current customers taking interruptible M16 service as service is limited by local market demands or would require significant storage facilities additions (i.e compressor).

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

current ROE formula would have served to increase the allowed ROE during the recent credit crisis, which, in the Board's view, would have been directionally correct.[64]

The Board has determined that it is appropriate to use a corporate yield variable that is reflective of the borrowing costs of Canadian utilities, one that is well-understood and is based on an established index from a recognized source. **The Board has** accordingly **determined that it will use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield.** This is further described in Appendix B.

The Board agrees with the comment of Ms. McShane that separating the LCBF and the utility bond spread variables, as opposed to using one corporate bond yield variable that would implicitly incorporate the LCBF, provides transparency as it shows "what part is causing the ROE to move in either direction."[65]

The Board also determines that the utility bond spread reflected in the reset and refined formulaic ROE approach will be subject to a 0.50 adjustment factor, consistent with the empirical analyses provided by participants to the consultation.

4.3 Capital structure

The Board's current policy with regard to capital structure for all regulated utilities continues to be appropriate. As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals. [66] The Board's current policy is as follows:

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[64] Written Comments of the Electricity Distributors Association. September 8, 2009. Schedule 4.
[65] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. Ms. McShane's presentation, p. 161.
[66] Ontario Energy Board. Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2

- The Board has determined that a split of 60% debt, 40% equity is appropriate for all electricity distributors. [67] Capital structure was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policy.

- For electricity transmitters, generators, and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk. [68]

4.4 Debt Rates

4.4.1 Long-term debt

The determination of the cost of long-term debt was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policies and practices.

While the Board agrees with this approach, it is important to note that the determination of the cost of long-term debt has typically received significant interest in the processes to establish electricity distribution and, to a lesser extent, electricity transmission rates. In contrast to the difficulty establishing the utility cost of equity that arises from a lack of transparency, the issues associated with the determination of a utility's long-term debt cost arise from different factors, including the relatively short period of time since the corporatization of electricity distribution and transmission utilities, the relatively short history of rate regulation by the Board, and the presence of significant amounts of affiliate debt.

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[67] Ontario Energy Board. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20, 2006. p. 5
[68] Ontario Energy Board. Compendium to Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March, 1997. p. 30

4.5 Summary

The key elements of the Board’s cost of capital policy are summarized in the following table.

Table 2: Components of the Board's Cost of Capital Policy

Capital structure	• 60% debt (56% long-term and 4% short-term) and 40% equity for electricity distributors. • Gas distributors, electricity transmitters and OPG will continue with approved capital structures.
Short-term debt rate	• Once a year, in January, obtain real market quotes from major banks, for issuing spreads over Bankers Acceptance rates for the cost of short-term debt. • The short term rate will be calculated as the average Bankers’ Acceptance for the month 3 months in advance of the effective date for the rates, plus the spread for the year calculated above.
Long-term debt rate	• The deemed long-term debt rate will be based on the Long Canada Bond Forecast plus an average spread with an A-rated long-term utility bond yield). • Third-party embedded/actual debt with fixed rates, terms and maturity will get the actual rate. • Affiliate embedded/actual debt with fixed rates, terms and maturity will get the lower of actual and deemed debt rate at time of issuance. • Utility provides forecasts of new debt for a forward test year, where possible. New third-party debt will be accepted at the negotiated market rate. If a forecasted new rate is not available (i.e., due to timing), the deemed long-term debt rate may apply. • For new affiliated debt, the deemed long-term debt rate will be a ceiling on the allowed rate. The onus will be on the utility to demonstrate that the applied for rate and terms are prudent and comparable to a market-based agreement and rate on arms-length commercial terms. • Variable-rate debt will be treated like new affiliated debt. • Renegotiated or renewed debt will be considered new debt. • Where a utility has no actual debt, the deemed long-term debt rate shall apply.
Common equity return	• Refined formula-based ROE will be calculated as the base ROE + 0.5 X (change in Long Canada Bond Forecast from base year) + 0.5 X (change in the spread of (A-rated Utility Bond Yield – Long Canada Bond Yield) from the spread in the base year). This includes an implicit 50 basis points for transactional costs. • The ROE (and the short-term and long-term debt rates) will be based on data for the month 3 months in advance of the effective date for rates. • Reset formula for 2010: The base ROE in the refined formula will be calculated for 2010 as Long Canada Bond Forecast rate plus an ERP of 550 basis points, and reflects multiple, empirically supported, estimates provided in consultation which led to this report.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit E1, Tab 1, pages 5-6, Updated

a) With respect to the weather risk, does the adoption of the proposed 20 year declining trend methodology reduce Union's weather risk relative to the current Board approved methodology? If no, please explain why not.

b) Please provide a table that shows the distribution revenue for each rate class broken into fixed revenues (based on monthly charges and demand charges) and variable revenues (based on delivery charges) based on the Board Approved 2007 rates and volumes and the proposed 2013 rates and volumes.

c) With respect to the consumption risk, please provide a historical analysis of the actual large commercial and industrial customers natural gas distribution revenues relative to the 2 year ahead forecast (i.e. comparable to the test year forecast) for the last three years.

d) With respect to the cost escalation risk, is Union proposing any protection through deferral or variance accounts related to bad debt, vehicle fuel costs, company-used gas, unaccounted for gas or any other cost?

e) Please provide a summary of the significant changes in the company's business and/or financial risk that have occurred since the Board approved Union's last cost of capital parameters.

Response:

a) The adoption of the 20-year declining trend weather normal methodology provides a more balanced weather risk relative to the current blended ratio methodology. The current blended methodology used to set the weather normal is biased towards colder weather and does not possess symmetric upside and downside revenue risks. The 20-year declining trend has symmetric revenue risks.

b)

Line No.	Particulars ($ millions)	2007 Board Approved Fixed	Variable	Total (1)	2013 Forecast Fixed	Variable	Total (1)
	General Service						
1	Rate M1 Firm	-	-	-	254	124	379
2	Rate M2 Firm	190	220	410	7	38	45
3	Rate 01 Firm	57	76	133	77	61	138
4	Rate 10 Firm	2	19	22	2	15	17
5	Total General Service	249	316	565	339	239	578
	Wholesale - Utility						
6	Rate M9 Firm	0	0	1	1	0	1
7	Rate M10 Firm	-	0	0	-	0	0
8	Rate 77 Firm	0	-	0	-	-	-
9	Total Wholesale - Utility	0	0	1	1	0	1
	Contract						
10	Rate M4	10	4	14	7	4	11
11	Rate M7	6	1	7	4	0	4
12	Rate 20	6	1	7	8	2	10
13	Rate 100	11	5	16	9	4	13
14	Rate T-1	37	18	55	44	14	58
15	Rate T-3	4	1	6	4	1	5
16	Rate M5	2	6	8	1	8	9
17	Rate 25	0	2	2	0	2	2
18	Rate 30	-	-	-	-	-	-
19	Total Contract	76	39	115	76	35	111
20	Total Revenue	325	356	681	416	274	689

Note: (1) EB-2011-0210 Exhibit C1 Summary Schedule 4 c)

Forecast to Actual Revenue Comparison ($ Millions)

Line No.	Market		2007	2008	2009	2010	2011
1	Power	Forecast	26.0	25.6	31.1	29.9	30.2
2		Actuals	26.8	26.3	29.0	32.2	32.7
3		*Variance*	*0.8*	*0.7*	*-2.1*	*2.3*	*2.5*
4	Steel/Chem/Ref	Forecast	38.9	38.6	41.9	37.4	36.4
5		Actuals	38.5	37.7	37.0	36.7	38.4
6		*Variance*	*-0.4*	*-0.9*	*-4.9*	*-0.7*	*2.0*
7	LCI/Key	Forecast	45.9	43.8	42.8	37.2	35.3
8		Actuals	45.1	43.9	39.5	36.8	36.4
9		*Variance*	*-0.8*	*0.1*	*-3.3*	*-0.4*	*1.1*
10	Greenhouse	Forecast	4.2	3.9	6.0	5.6	5.2
11		Actuals	3.9	5.2	4.9	5.8	6.3
12		*Variance*	*-0.3*	*1.3*	*-1.1*	*0.2*	*1.1*
13	Wholesale	Forecast	6.1	6.3	6.3	6.0	5.6
14		Actuals	5.5	5.7	5.8	5.7	5.5
15		*Variance*	*-0.6*	*-0.6*	*-0.5*	*-0.2*	*0.0*
16	Grand Total	Forecast	121.1	118.3	128.0	116.1	112.7
17		Actuals	119.8	118.8	116.2	117.2	119.3
18		*Variance*	*-1.3*	*0.5*	*-11.8*	*1.2*	*6.7*

d) Union is not proposing any new deferral accounts in this proceeding.

e) Union has not performed an analysis of its financial or business risk because Union's proposal to increase its equity level to 40% is not based on changes in risk.

Union's proposal to increase its equity level from 36% to 40% is based on a comparison of other utilities with similar risk profiles as Union. As noted at Exhibit J.E-2-3-6, Union's equity level is the lowest in the comparator group even though the business risks of the utilities are comparable. A 40% equity level for Union properly reflects Union's business risks when viewed in conjunction with the Board's revised return on equity formula (EB-2009-0082).

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Mr. Broeders

Please confirm if Union accepts that its financial and business risk have either remained unchanged or have declined since last analyzed by Dr. Carpenter of the Brattle Group.

Union has not analyzed it business and financial risks, but accepts that its overall risk profile has not materially changed 2004. Dr. Carpenter's evidence was part of the evidence filed by the Brattle Group in EB-2005-0520. Written evidence was also prepared by Dr. Kolbe and Dr. Vilbert.

The Brattle Group's evidence is attached as Attachments 1, 2 and 3. It was the Brattle Group's opinion that the appropriate deemed equity level for Union ranged between 40% and 56% depending upon the allowed return on equity.

Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME:	**4**	
DATE:	**July 16, 2012**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

business risk have either remain unchanged or have declined -- I think it should say "have not declined" -- since last analyzed by Dr. Carpenter of the Brattle Group.

The response was Union has not analyzed its business and financial risks. Is that correct?

MR. BROEDERS: Sorry, just give me a minute.

The answer to the undertaking is saying that we have not analyzed our business and financial risk, but we accept that its overall risk profile has not materially changed since 2004.

MR. THOMPSON: All right. So whatever you have asked the experts to do, you did not ask them to analyze whether Union's -- there have been any significant changes in the company's business and/or financial risks since 2007. They were not asked to do that?

MR. BROEDERS: That's correct.

MR. THOMPSON: And Union accepts that its overall risk profile is not materially changed since -- from 2004. You don't take it to 2007 only. You go back to 2004.

You accept that your overall risk profile has not materially changed; is that correct?

MR. BROEDERS: That's correct. We have submitted evidence based on the comparables and we believe that the risk, as we submitted in 2004, which has not materially changed to this day, is not commensurate with the equity percentage that we have.

MR. THOMPSON: All right. So I suggest to you it is the end of the story. You cannot discharge the

BUSINESS RISK AND CAPITAL STUCTURE FOR UNION GAS

EB-2011-0210

Evidence of

Laurence D. Booth

Before the

Ontario Energy Board

May 2012

EXECUTIVE SUMMARY

- Union Gas Limited ("Union") is a business corporation incorporated under the laws of the province of Ontario, with its head office in Chatham-Kent, that conducts both an integrated natural gas utility business that combines the operations of distributing, transmitting and storing natural gas, and a non-utility business. In this proceeding, Union has applied to the Ontario Energy Board ("Board"), pursuant to section 36 of the Ontario Energy Board Act 1998 (the "ACT") for an order or orders approving or fixing just and reasonable rates and other changes for the sale, distribution, transmission and storage of gas effective January 1, 2013. Included in the application by Union is a request for the Board approval of Union's proposed change in capital structure increasing Union's common equity component from 36% to 40% (described at Exhibit E1. Tab 1)
- Capital structure is mainly determined by two factors: the business risk of the utility and the general state of the capital markets. Union's short term business risk is very low as it continues to earn its allowed ROE. Further there is no indication that the impact of the five year IRM period has exposed Union's shareholder to any increase in risk. In fact while under IRM, Union's tendency to over earn has increased. Union's long term risk has demonstrably decreased since natural gas prices have collapsed, so the risk of long term recovery of Union's rate base has diminished relative to 2006, when Union last filed business risk testimony.
- In my judgment, the business risk of Union has marginally decreased relative to RP-2003-0063/87/97 when Union requested and was granted a 35% common equity ratio in the Board's decision dated March 18, 2004.[1] Union then requested a 40% common equity ratio in 2006 which was settled at 36%, so Union's last litigated common equity ratio was 35%. On business risk grounds there is no justification for increasing Union's common equity ratio from 35% to 40%.
- Financial market conditions are more unsettled than in 2004 or 2006 due to external factors; mainly the Euro sovereign debt crisis and the endemic problems in the United States. However, the Board dealt with the impact of capital market issues in 2009 by rebasing the formula ROE and changing the allowed ROE in line with credit market

[1] Union Gas was a given a little bump in EBRO499 when it's common equity ratio was increased to 35% from 34% after it was consolidated with Centra Gas Ontario, which had a 36% common equity ratio. A straight blended rate would have been 34.5%. Historically Union had a 29% common equity ratio.

developments.[2] Should the Board allow Union its formula ROE then there are no grounds for adjusting the common equity ratio for these changes, since that would amount to double counting their effect. Further the Board approved ROE materially exceeds the allowed ROEs recently awarded in other Canadian jurisdictions.[3] This combined with the marginal decrease in Union's business risk suggests that Union should no longer be allowed a 0.15% premium over that allowed Enbridge Gas Distribution (EGDI).

- Overall I would recommend that Union be allowed a 35% common equity ratio[4] and the Board's formula ROE without any premium. I have not entered ROE testimony since the Board will review its formula ROE in 2014, but I would comment that currently Board-allowed ROEs are at the very top of, if not exceeding, the range of a fair and reasonable ROE for a low risk Canadian utility like Union Gas.
- With a 35% common equity ratio and the Board allowed ROE, the financial metrics for Union Gas will be better than during the term of the settlement when Union's allowed ROE was fixed at 8.54%. During this time Union maintained a very strong A rating from DBRS as well as excellent access to the commercial paper market with an R-1 (low) rating. Union's BBB+ S&P rating is due to its ownership by a weak parent, since it is a flow through of Spectra Energy's S&P BBB+ rating. S&P is much more cautious than DBRS in awarding stand-alone credit ratings to regulated utility subsidiaries given the history in the US of public utility commissions not protecting utilities from actions by their parent. This is simply one aspect of the greater risk faced by investors in US public utilities- there is greater regulatory protection in Canada.[5]

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[2] EB-2009-0084 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities

[3] By Board letter November 10, 2011 the OEB allowed ROE for 2012 is 9.42%, by comparison the AUC allowed ROE for 2012 is 8,75% (Decision 2011-474, December 8, 2011). The additional 0.67% for Ontario utilities cannot be justified on economic or financial grounds. Towers Watson, Union's actuaries are using 6.30-8.00% for the expected return on Canadian equities in valuing Union's pension fund J.E-2-12-6, while its current cost of long term debt is less than 4%.

[4] This is consistent with the terms of Spectra Energy's 10K filed with the SEC and its credit agreement stipulating no more than 65% debt (page 46 Annual Report)

[5] When the Board agreed to Union's requested 35% common equity ratio in its 2004 decision Union had an A- S&P bond rating and in 2002 it was A, now it is BBB+. Obviously Union's common equity ratio should not be increased simply because it is now owned by a weak US parent.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit E1, Tab 1, page 4

Union's evidence indicates that the approved capital structure must allow the company to raise capital in the market when it is needed under reasonable terms and conditions. Union's proposal to increase the common equity component to 40% provides financing capacity for Union's investment growth forecast for 2013.

a) Please indicate all cases in the last 5 years where Union Gas has had to defer or abandon expenditures needed to provide service due to an inability to raise the necessary capital under reasonable terms and conditions. Please provide details.

b) What will be the impact on Union's ability to raise capital if the Board does not approve Union's proposed capital structure?

Response:

a) Union has not had a specific case where the Company has not been able to issue debt to finance capital investment within the last five years. Previously, there have been situations when the Company was limited by the interest coverage test to the timing and the amount of the debt issue.

b) If the Board approves Union's proposal to increase its equity to 40%, it will improve Union's ability to raise capital.

to an IR framework." The Board specified on page 112 of the EB-2005-0551 Decision with Reasons that the proposed elimination of the three transmission-related accounts should be considered as part of a comprehensive review that includes all deferral accounts under an incentive regulation mechanism. Therefore, Union is requesting the elimination of the following three deferral accounts (Transportation Exchange Services Account (179-69), Other S&T Services Account (179-73) and Other Direct Purchase Services Account (174-74)) beginning January 1, 2008. Board staff supported the elimination of the three deferral accounts in the Board Staff paper (page 22). The Long-Term Peak Storage Services Account (179-72) is discussed in Section 5.8.3 below.

4. DSM is discussed in Section 5.8.2

Weather Normalization Method

Union proposes that the 20-year declining trend weather forecasting method be fully implemented effective January 1, 2008 as an adjustment to base rates. This would result in an estimated impact to rates of approximately $7 million.

This adjustment would produce greater symmetry in weather risk (i.e. colder weather being as likely to occur as warmer weather.) Using the current 55% 30-year average and 45% 20-year declining trend blended method ("55/45 blend") represents a substantial risk to the company. The use of the 30-year average has a bias toward exceeding the actual number of heating degree days ("HDDs"). Forecasting the HDDs through use of the

UNION GAS LIMITED

Undertaking of Mr. Aiken
To Mr. Broeders

Please calculate actual equity component.

The actual equity components are at a point in time and for the total company (regulated and unregulated business).

	December 2011	June 2012
Preference shares	2.85%	2.96%
Common equity	33.29%	36.50%
Total	36.14%	39.46%

UNION GAS LIMITED

Undertaking of Mr. Millar
To Mr. Broeders

Please explain what portion is for preference equity is treated as debt versus equity by the auditors.

With the change to US GAAP all of Union's preference shares are classified as equity.

UNION GAS LIMITED
Summary of Cost of Capital
Calendar Year Ending December 31, 2013

Line No.	Particulars	Utility Capital Structure ($000's)	Utility Capital Structure (%)	Cost Rate %	Requested Return ($000's)
		(a)	(b)	(c)	(d)
	As Filed				
1	Long-term debt	2,257,972	60.35	6.50%	146,868
2	Unfunded short-term debt	(115,296)	(3.08)	1.31%	(1,510)
3	Total debt	2,142,676	57.27		145,358
4	Preference shares	102,248	2.73	3.05%	3,117
5	Common equity	1,496,617	40.00	9.58%	143,376
6	Total rate base	3,741,542	100.00		291,851
	Per Settlement Agreement				
7	Long-term debt	2,234,597	60.17	6.53%	145,957
8	Unfunded short-term debt	(108,513)	(2.92)	1.31%	(1,422)
9	Total debt	2,126,084	57.25		144,535
10	Preference shares	102,248	2.75	3.05%	3,117
11	Common equity	1,485,555	40.00	9.58% (2)	142,316
12	Total rate base	3,713,887	100.00		289,969
13	Change	(27,655) (1)			(1,883)

Notes

(1) Reductions to rate base

general	(12,000)
gas in inventory	(15,655)
	(27,655)

(2) Per Section 4.3 of the settlement agreement

UNION GAS LIMITED
Cost of Long-Term Debt Capital
Year Ending December 31, 2013

Line No.	Offering Date (a)	Coupon Rate (b)	Maturity Date (c)	Principal Amount Offered ($000's) (d)	Premium Discount and Expenses ($000's) (e)	Net Capital Employed: Total Amount ($000's) (f)	Net Capital Employed: Per $100 Principal Amount (in Dollars) (g)	Effective Cost Rate [1] (h)	Total Amount Outstanding: at 12/31/12 ($000's) (i)	Total Amount Outstanding: at 12/31/13 ($000's) (j)	Avg. Monthly Averages ($000's) (k)	Carrying Cost ($000's) (l)	Projected Average Embedded Cost Rates (m)
1	08/28/90	11.50	08/28/15	150,000	1,620	148,380	98.92	11.63	150,000	150,000	150,000	17,445	
2	11/06/92	9.70	11/06/17	125,000	1,500	123,500	98.80	9.83	125,000	125,000	125,000	12,288	
3	08/05/93	8.75	08/03/18	125,000	1,275	123,725	98.98	8.90	125,000	125,000	125,000	11,125	
4	10/19/93	8.65	10/19/18	75,000	908	74,092	98.79	8.79	75,000	75,000	75,000	6,593	
5	02/24/93	7.90	02/24/14	150,000	1,869	148,131	98.75	8.04	150,000	150,000	150,000	12,060	
6	11/10/95	8.65	11/10/25	125,000	1,612	123,388	98.71	8.79	125,000	125,000	125,000	10,988	
7	09/21/05	4.64	06/30/16	200,000	1,100	198,900	99.45	4.70	200,000	200,000	200,000	9,400	
8	09/11/06	5.46	09/11/36	165,000	898	164,102	99.46	5.51	165,000	165,000	165,000	9,092	
9	11/23/06	4.85	04/25/22	125,000	854	124,146	99.32	4.91	125,000	125,000	125,000	6,138	
10	04/28/08	5.35	04/27/18	200,000	1,060	198,940	99.47	5.42	200,000	200,000	200,000	10,840	
11	09/02/08	6.05	09/02/38	300,000	2,076	297,924	99.31	6.10	300,000	300,000	300,000	18,300	
12	07/23/10	5.20	07/23/40	250,000	2,455	247,545	99.02	5.27	250,000	250,000	250,000	13,175	
13	06/21/11	4.88	06/21/41	300,000	2,171	297,829	99.28	4.93	300,000	300,000	300,000	14,790	
14	10/01/12	3.85	10/01/22	125,000	515	124,485	99.59	3.90	125,000	125,000	125,000	4,875	/c
15									2,415,000	2,415,000	2,415,000	157,109	6.51%
16	Regulated Portion										2,257,972	146,868	6.50%

Note:

(1) Computation of effective cost rate takes into account sinking fund requirements and the amortization of any premium/discount and issue expenses, on the average life of each iss

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **5**

DATE: **July 17, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

debt next year; is that right? So instead of being 6.50 percent, it is 6.53 percent on long-term debt; right?
MR. BROEDERS: That's correct.
MR. SHEPHERD: And that is because less rate base means you borrow less?
MR. BROEDERS: Correct. When we decreased -- in the settlement, we said we decreased the long-term debt by $25 million because that was at a 3.9 rate versus the 6.5 rate. The average rate goes up, yes.
MR. SHEPHERD: And so then with that, then, understanding, are these calculations, subject again to rounding errors, roughly correct, so that is your cost of capital under the settled rate base under the existing capital structure?
MR. BROEDERS: The calculations look correct.
MR. SHEPHERD: Okay, thank you.
And just one thing, and I am going to come back to this again in a second -- and you've talked about this a little bit. I just want to make sure I understand this. Your long-term debt is actually more than the amount of the long-term debt that you're -- the amount of total debt that you are authorized, and so the effect of this is that you have short-term debt which is a negative; right?
MR. BROEDERS: The long-term debt that is shown in the second section, the 2,234 --
MR. SHEPHERD: Still in the first, sorry.
MR. BROEDERS: The 2,289 is a calculated number. It's not indicative of our real debt. I am just trying to make

the point that the short-term debt is a result of our real long-term debt.

MR. SHEPHERD: The reason I ask that is because one of the effects of that is that the total cost of your debt is actually higher than the cost of your long-term debt; right? You didn't include in Exhibit J.E-1-1-1 the total cost rate of your debt, but we've actually done that calculation, 6.61 percent.

And that's the effective cost of all of your net debt, right, under the existing capital structure? It is just the total of -- the total interest cost divided into the total debt, net debt?

MR. BROEDERS: Yes.

MR. SHEPHERD: Okay. And the reason for that is that effectively this way of calculating assumes that, under the existing capital structure, you borrow $33 million at 6.53 percent, and then you invest it at 1.31 percent; correct?

MR. BROEDERS: That's what the numbers are insinuating, but that's not the cause of the negative short-term debt.

MR. SHEPHERD: No. The cause is that you need to get to the correct percentages; right?

MR. BROEDERS: The cause of negative short-term debt is because there are items outside of rate base that the utility has to invest in, such as construction work-in-progress and the contributions in excess of the expense for pension.

That amounts to, for 2013, about $250 million.

MR. SHEPHERD: However, the effect of this is that you have paid a little over $2 million for that $33 million at 6.53 percent, and you got $433,000 back for it; right? The difference is paid for by the ratepayers?

MR. BROEDERS: That's what these numbers are implicitly showing, but it's not -- it is not what's happening. We're not going out and investing or getting long-term debt to charge ratepayers as 4 percent so we can go earn 1 percent.

The negative short-term debt is just a result -- this negative short-term debt, which is really -- it appears to be a cash position, so similar to what you were saying, but it's not what is actually happening on our short-term debt when we're issuing commercial paper.

Our average borrowings for 2013 is predicted to be about $136 million for short-term, whereas this is suggesting it would be investing.

MR. SHEPHERD: Okay. Then now I want to go to the second section here, and we took the -- again, the percentages, all the various percentages from the settlement agreement.

If you could just go to page 5 of our materials, this is where you've set these figures out. And I just want to point out one thing, and I know you were going to point it out, anyway, so I will give you the opportunity.

On line 9 at page 5 of our materials, you will see it says the total debt is 2.142 billion or -- yes, billion.

and, after the financial crisis, Union's got to have more equity? That is the simple message; right? That is the elevated --

DR. VANDER WEIDE: I wouldn't use the word "all". I would say it is about risk and the perception of risk, and that perception has changed in recent years.

MR. SHEPHERD: Thank you, Madam Chair. Those are our questions.

MS. HARE: Thank you.

QUESTIONS BY THE BOARD:

MS TAYLOR: Sorry, I would like to come back to page 2 of Mr. Shepherd's compendium.

The answer that you gave, and we will compare that I guess to page 4, and Mr. Shepherd discussed -- sorry, page 5, rather, of his compendium.

Your answer, about the long-term debt appears to be greater than 60 percent, was that there are other factors that are outside of rate base that need to be financed, and that's why they're showing up not only on page 2, but on page 5; is that correct?

MR. BROEDERS: That's correct.

MS. TAYLOR: So given that we're dealing with a rate-regulated entity and these are matters that will flow through rate base, why is it appropriate to show amounts of debt that actually are not included in rate base in these schedules?

MR. BROEDERS: There are utility operations that are not included in rate base. For instance, when we're investing in capital and building things, like Parkway West, those items are completely funded by the utility, but they're outside of rate base until they come into service.

MS. TAYLOR: Right. So, you know, on page 5, this appears to be a Union Gas schedule. It says, "Summary of cost of capital calendar year ending December 31st, 2013." And we've got more than 60 percent in debt.

And you're saying that at least from a long-term perspective, that is to finance things the Board has not yet agreed to put into rate base; is that correct?

MR. BROEDERS: Those things are primarily being funded out of short term. But the problem is, when you come to the schedule and you try to impute what the short-term debt is, you have to work with the set rate base figure. The long-term debt is what it is and --

MS. TAYLOR: Well, it is what it is, but if the rate base for rate-making purposes and for the amount of costs that flow through is set at a number that is lower, you have a deemed capital structure for that purpose.

So what you're suggesting or what I am taking from this is you've actually got more here than at this point in time flows into rates; is that correct?

MR. BROEDERS: Some of this is also in relation to shifting from a 36 percent to a 40 percent, and we're kind of in between years.

So our long-term debt, if you didn't have the 40 percent equity component that has been implied through here, this would show at 36, and then that long-term debt comes into a more reasonable number.

The problem is that we're shifting -- it is basically a $150 million shift. So there is that. There is also the components of the utility operations that are outside of this that don't come into the rate base.

So it's -- I take your point. You're saying that the long-term debt appears to be higher, that we're putting things into long-term debt before they have been approved by the Board, either of the CWIP or the preferred pension cost.

The deferred pension costs are a longer-term item and are also likely getting into the long-term debt.

MS. TAYLOR: So I would like you to do, if possible -- because I think we need to figure out exactly what the long-term debt is that we're dealing with, at 36 percent that is solely attributable to rates for 2013, assuming the status quo, and then if you go to 40 percent, what would be the long-term debt and cost?

Because we are mixing up apples and oranges. CWIP is not in rates yet; you don't have approval for that. Parkway is not in rates; you don't have anything for that yet. And we have been asked not to -- I guess we will deal with that in a few minutes or a few days.

So I would like to understand what the numbers are, because I don't understand these tables on 2 and page 5, and that you've brought in non-utility numbers into a rate base calculation.

MR. BROEDERS: Well...

MS. TAYLOR: If you could just perhaps restate these tables to show me exactly what it is, at 36 percent, the world looks like from a long-term debt, short-term debt, total debt perspective, pref and common equity perspective.

And then if you are to go to 40 percent, what would that mean, using the numbers for rate base that were in the settlement agreement.

MR. BROEDERS: Okay.

MR. SMITH: Yes, we will do that.

MS. TAYLOR: Thank you.

MR. MILLAR: J5.4.

UNDERTAKING NO. J5.4: TO RESTATE TABLES TO SHOW SITUATION AT 36 PERCENT AND 40 PERCENT.

MS. HARE: Mr. Millar, your cross-examination, please?

MR. MILLAR: Yes. Thank you, Madam Chair.

Good morning, panel --

MS. HARE: I'm sorry, Mr. Millar. I think Mr. Sommerville has a question.

MR. SOMMERVILLE: This just relates to what may be consequential to that revised exhibit.

Mr. Shepherd, you prepared a series of schedules that were predicated on the -- I think, on the initial exhibit.

Do you need to restate those tables?

MR. SHEPHERD: Mr. Sommerville, if my friend would give us the Excel that backs up their new table, then we can adjust this and ask them to approve it.

I don't think there is a disagreement on the numbers. I think what Ms. Taylor is asking for is a different way of

REQUESTED RETURN
(BASED ON SETTLEMENT AGREEMENT, APPENDIX B, SCHEDULE 3

A. Per Settlement Agreement

	($000's)	(%)	Cost Rate %	Requested Return ($000's)
Long-term debt	2,234,597	60.17%	6.53%	145,957
Short-term debt	-108,513	-2.92%	1.31%	(1,422)
Total debt	2,126,084	57.25%		144,536
Preference Shares	102,248	2.75%	3.05%	3,117
Common Equity	1,485,555	40.00%	9.58%	142,316
Total rate base	3,713,887			289,968

B. 40% Common Equity

	($000's)	(%)	Cost Rate %	Requested Return ($000's)
Long-term debt	1,990,200	53.59%	6.53%	129,960
Short-term debt	136,000	3.66%	1.31%	1,782
Total debt	2,126,200	57.25%		131,742
Preference Shares	102,132	2.75%	3.05%	3,115
Common Equity	1,485,555	40.00%	9.58%	142,316
Total rate base	3,713,887			277,173

C. 40% Equity

	($000's)	(%)	Cost Rate %	Requested Return ($000's)
Long-term debt	2,092,332	56.34%	6.53%	136,629
Short-term debt	136,000	3.66%	1.31%	1,782
Total debt	2,228,332	60.00%		138,411
Preference Shares	102,132	2.75%	3.05%	3,115
Common Equity	1,383,423	37.25%	9.58%	132,532
Total rate base	3,713,887			274,058

D. Status Quo

	($000's)	(%)	Cost Rate %	Requested Return ($000's)
Long-term debt	2,138,756	57.59%	6.53%	139,661
Short-term debt	136,000	3.66%	1.31%	1,782
Total debt	2,274,756	61.25%		141,442
Preference Shares	102,132	2.75%	3.05%	3,115
Common Equity	1,336,999	36.00%	9.58%	128,085
Total rate base	3,713,887			272,642

UNION GAS LIMITED
Southern Operations Area
Percentage Change in Average Unit Price
Effective January 1, 2013

Line No.	Particulars (cents/m^3)	Rate Classification	Current Approved Rates (1) (cents / m^3)	Rate Change	Approved Rates (2) (cents / m^3)	Percent Change (3) (%)
			(a)	(b) = (c - a)	(c)	(d) = (b / a)
	General Service	M1				
1	Delivery		12.2449	0.7712	13.0161	6.3%
2	Storage		0.9775	(0.1861)	0.7914	-19.0%
3	Total		13.2224	0.5851	13.8075	4.4%
	General Service	M2				
4	Delivery		3.8878	0.4954	4.3832	12.7%
5	Storage		0.7200	0.0899	0.8099	12.5%
6	Total		4.6078	0.5853	5.1931	12.7%
	Firm Contract Commercial / Industrial	M4				
7	Delivery		2.8157	0.5020	3.3177	17.8%
	Firm Contract Commercial / Industrial	M5 (F)				
8	Delivery		2.7592	0.3615	3.1207	13.1%
	Interruptible Contract Commercial / Industrial	M5 (I)				
9	Delivery		1.6298	0.6237	2.2535	38.3%
	Firm Special Large Volume Contract	M7 (F)				
10	Delivery		2.7417	0.0849	2.8266	3.1%
	Interruptible Special Large Volume Contract	M7 (I)				
11	Delivery		0.9551	0.0852	1.0403	8.9%
	Large Wholesale Service	M9				
12	Delivery		1.3486	(0.0847)	1.2639	-6.3%
	Small Wholesale Service	M10				
13	Delivery		2.5245	0.3940	2.9185	15.6%
	Storage and Transportation	T1 (F/I)				
14	Delivery		1.1187	(0.0680)	1.0508	-6.1%
15	Delivery excluding fuel		1.0093	(0.0014)	1.0079	-0.1%
16	Storage and Transportation Distributor	T3	1.6762	0.0335	1.7097	2.0%

Notes:
(1) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (c).
(2) EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, column (h).
(3) Excludes Gas Supply Commodity related costs.

Table 1

System Integrity Storage Space Allocation of Hysteresis

			Excess Utility Storage Space		
Line No.	Storage Space Component (PJ)	In-Franchise (a)	Short-Term (b)	Long-Term (c)	Total (a+b+c = d)
1	In-franchise Storage Space	77.5			77.5
2	Short-Term and Long-Term Storage Space[(1)]		13.0	66.5	79.5
3	System Integrity Space [(2)]	6.6	0.1	0.3	6.9
4	Revised Storage Space (Lines 1 + 2 + 3)	84.1	13.0	66.8	163.9
5	Allocation of Filled Space of Hysteresis [(3)]	0.6	0.1	0.5	1.2
6	Revised Storage Space less Short-Term and Long-Term Storage Space (Lines 1 + 3)	84.1	0.1	0.3	84.4
7	Allocation of Empty Space of Hysteresis [(4)]	0.7	0.0	0.0	0.7

(1) Storage Space includes total working storage capacity less non-utility third party storage space.

(2) System integrity space excludes space reserved for the Hagar LNG facility and storage hysteresis (9.5 PJ less 2.6 PJ).

(3) System Integrity Space required for filled hysteresis space is allocated based on the revised storage space (Line 4).

(4) System Integrity Space required for empty hysteresis space is allocated based on the revised storage space less short-term and long-term storage space (Line 6).

2/ TECUMSEH METERING ASSETS

Union proposes to change the classification and allocation of costs associated with Tecumseh metering assets.

In Union's Board-approved 2007 cost allocation study, certain Tecumseh metering assets at the Dawn facility were reflected as transmission assets in Union's plant accounting records. These metering assets were directly assigned to the Dawn Station transmission function and the Dawn

Station Customer classification. The costs were then allocated to the M12 rate class based on Tecumseh metering demands.

Based on a review of the Tecumseh metering assets, Union updated the plant accounting records to move the assets from transmission to underground storage. However, as the Tecumseh metering assets continue to provide transmission service, Union direct assigned the Tecumseh metering assets to the Dawn Station transmission function. Similar to other underground storage assets functionalized to Dawn Station, Union proposes to classify the costs to Demand and allocate the costs to rate classes based on the design day demands of Dawn compression. Union also proposes to eliminate the Dawn Station Customer classification, as the Tecumseh metering costs were the only costs previously allocated to this functional classification.

The impact of the change to rate classes is provided at Appendix B. A description of the underground storage asset re-classifications to the transmission function is provided at Exhibit G3, Schedule 1.

3/ OIL SPRINGS EAST ASSETS

Union proposes to change the functionalization, classification and allocation of costs associated with Oil Springs East assets.

In Union's Board-approved 2007 cost allocation study, Union directly assigned the structure and improvements and measuring and regulating equipment plant costs associated with the Oil

Springs East storage pool to the Dawn Trafalgar Easterly transmission function. This re-classification from underground storage to transmission was based on the use of the assets, which previously served Union North transmission needs. Union also classified the costs to the Dawn Trafalgar Easterly Oil Springs East Metering classification, and allocated costs to rate classes based on design day demands on the Dawn Parkway transmission system.

Union's review of Oil Springs East storage pool assets has determined that these assets now provide both storage and transmission services to customers. Accordingly, Union proposes to eliminate the direct assignment of Oil Springs East assets to the Dawn Trafalgar Easterly transmission function and functionalize these assets between storage and transmission. This approach is consistent with the treatment of other underground storage assets at the Dawn facility that provide both storage and transmission services. Given Union's proposal to eliminate the direct assignment of Oil Springs East assets, Union also proposes to eliminate the transmission classification of Dawn Trafalgar Easterly Transmission for Oil Springs East metering. The impact of the change is provided at Appendix B.

4/ NEW EX-FRANCHISE TRANSPORTATION SERVICES

Since Union's Board-approved 2007 cost allocation study was completed, several new ex-franchise transportation services have been developed by Union and approved by the Board. Specifically, Union has developed the C1 Dawn to Dawn-TCPL and C1 Dawn to Dawn-Vector firm transportation services, as well as the M12 firm all day (F24-T) transportation service. Union proposes to include the costs associated with these new transportation services in its 2013

Union proposes to continue to allocate customer station costs based on the average number of customers, excluding the Rate 01 rate class and Rate 10 customers that do not meet the annual consumption threshold of 934,400 m^3. The impact of the change is provided at Appendix B.

ii) Distribution Maintenance– Meter and Regulator Repairs

Union currently classifies Union South distribution maintenance costs for meter and regulator repair to Distribution Customer and allocates the costs to the M2 rate class. For Union North, distribution maintenance costs for meter and regulator repair are classified to Distribution Demand and allocated to rate classes in proportion to the allocation of distribution meter and regulator gross plant.

Based on a review of its operating practices, Union has determined that there are minimal maintenance costs associated with residential meters because it is more economical to replace small residential meters than perform repairs. To reflect Union's operating practices and harmonize cost allocation between Union North and Union South, Union proposes to align the Union North and Union South distribution maintenance meter and regulator repair cost methodology.

Accordingly, Union proposes to classify and allocate both Union North and Union South distribution maintenance costs for meter and regulator repair in proportion to the distribution meter and regulator gross plant cost allocation, excluding the M1 and Rate 01 rate classes. The impact of the change is provided at Appendix B.

iii) Distribution Maintenance– Equipment on Customer Premises

Union currently allocates Union South distribution maintenance costs for equipment on customer premises to M1 and M2 customers based on service call time. Union North distribution maintenance costs for equipment on customer premises are allocated to rate classes based on a historic allocator.

The maintenance of equipment on customer premises costs are primarily related to customer station maintenance. To more accurately reflect costs and to harmonize the approach between Union North and Union South, Union proposes to allocate both the Union North and Union South equipment on customer premises distribution maintenance costs to rate classes in proportion to the allocation of customer station gross plant. The impact of the change is provided at Appendix B.

iv) Purchase Production General Plant

Union currently functionalizes general plant costs in proportion to the functionalization of rate base and O&M costs. However, general plant costs are functionalized to the Purchase Production function based on O&M costs only since there are no other plants costs functionalized to Purchase Production. The Purchase Production general plant costs are

UNION GAS LIMITED
Revenue Requirement Impacts

Line No.	Particulars ($000's)	Cost Type	Revenue Requirement Total	Gen. Service Small Volume M1	Gen. Service Large Volume M2	Firm Contract M4	Interruptible Contract- Firm M5	Interruptible Contract- Interruptible M5	Special Large Volume Contract - Firm M7	Special Large Volume Contract - Interruptible M7	Large Wholesale Service M9	Small Wholesale Service M10	Storage & Transportation Service - Firm T1	Storage & Transportation Service - Interruptible T1	Wholesale Storage & Transportation Service T3
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	System Integrity Hysterisis	Allocator	0	60	21	3	0	4	1	0	1	0	19	0	5
2	Tecumseh Metering Assets	Rate Base	0	131	44	14	0	0	5	0	2	0	101	0	11
3	Oil Springs East Storage Pool	Rate Base	0	27	9	2	0	0	1	0	0	0	16	0	2
4	Distribution Maintenance - Meter and Regulator Repairs	O&M	0	(5)	(434)	65	1	71	28	4	5	1	188	45	19
5	Distribution Maintenance - Equipment on Customer Premises	O&M	0	(324)	92	35	1	39	15	2	3	0	102	24	10
6	Purchase Production General Plant	Rate Base	0	(169)	(91)	(16)	14	(41)	(28)	0	(11)	0	41	14	2
7	Distribution North Customer Stations	Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0
8	**Revenue Requirement Change[1]**		**0**	**(279)**	**(358)**	**103**	**15**	**74**	**22**	**7**	**(1)**	**2**	**467**	**83**	**51**

(1) A positive value represents an increase to the revenue requirement based on the proposed methodology.

UNION GAS LIMITED
Revenue Requirement Impacts

Line No.	Particulars ($000's)	Cost Type	Excess Utility Storage Space	Firm Transportation Service C1	Interruptible Trans. Service & Exchanges C1	Dawn-Trafalgar Transport Service M12	Local Production Transportation Service M13	Storage Transportation Service M16	Small Volume General Firm Service R01	Large Volume General Firm Service R10	Medium Volume Firm Service R20	Large Volume High Load Factor Firm Service R100	Large Volume Interruptible Service R25
			(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)
1	System Integrity Hysterisis	Allocator	(146)	0	1	4	0	0	20	5	1	0	0
2	Tecumseh Metering Assets	Rate Base	0	(0)	0	(306)	(1)	(0)	(2)	(1)	(0)	(0)	0
3	Oil Springs East Storage Pool	Rate Base	7	1	0	(77)	0	0	8	2	1	0	0
4	Distribution Maintenance - Meter and Regulator Repairs	O&M	-	-	-	-	-	-	(27)	45	(4)	(14)	12
5	Distribution Maintenance - Equipment on Customer Premises	O&M	-	-	-	-	-	-	(1,493)	286	532	152	523
6	Purchase Production General Plant	Rate Base	0	0	0	0	0	0	166	30	48	14	27
7	Distribution North Customer Stations	Rate Base	0	0	0	0	0	0	0	(2,169)	955	274	940
8	**Revenue Requirement Change[1]**		**(138)**	**1**	**1**	**(379)**	**(1)**	**0**	**(1,329)**	**(1,802)**	**1,533**	**427**	**1,502**

(1) A positive value represents an increase to the revenue requirement based on the proposed methodology.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit G1, Tab 1, page 7

a) How were Tecumseh metering assets classified/functionalized in EB-2005-0520?

b) Please explain in detail the change in allocation.

c) Specifically, why are the costs now allocated to in-franchise classes other than M12?

Response:

a) In Union's Board-approved 2007 cost allocation study from the EB-2005-0520 proceeding, the Tecumseh metering assets were directly assigned to the Dawn Station transmission function and classified to the Dawn Station Customer classification.

b) In EB-2005-0520, the costs associated with the Tecumseh metering assets were allocated to the M12 rate class based on Tecumseh metering demands.

   In the 2013 cost allocation study, Union is proposing to allocate the costs associated with the Tecumseh metering assets based on the design day demands of Dawn Compression. This allocation results in 78 percent of the costs being allocated to the M12 rate class and 22 percent to in-franchise customers.

c) Union is proposing to allocate Tecumseh metering costs to in-franchise rate classes based on the design day demands of Dawn compression to recognize that the assets provide a transmission service to both M12 and in-franchise customers. This approach is consistent with the cost allocation of other interconnects in the Dawn Station yard and results in an allocation of costs that better reflects cost incurrence than the Board-approved 2007 cost allocation described above.

1.6 ARE THE METHODS PROPOSED BY UNION TO ALLOCATE THE COST AND USE OF CAPITAL ASSETS BETWEEN REGULATED AND NON-REGULATED ACTIVITIES APPROPRIATE, AND ARE THE PROPOSED ALLOCATIONS TO THE REGULATED BUSINESS APPROPRIATE FOR THE TEST YEAR?

(Complete Settlement)

At Exhibit J.D-16-10-1, part b, Union identified $0.344 million of system integrity costs related to Union's non-utility storage space of 66.5 PJ. Consistent with Exhibit L.G-4-1-1, Union agrees that for the purpose of calculating the 2013 revenue requirement through the short-term storage margin available for sharing with ratepayers, the system integrity costs related to Union's non-utility storage space of $0.344 million will be excluded from that calculation. Parties acknowledge that the system integrity costs related to Union's non-utility storage space will change as a result of this agreement and may also change as a result of the Board's determination of the unsettled issues.

Evidence References: A2/T2, J.B-6-1-1, J.B-6-4-1, J.B-6-4-2, J.B-6-4-3, J.B-6-10-1, J.B-6-15-1, J.B-6-16-1, J.D-16-10-1, JT1.23, JT1.28, JT1.34, L.G-4-1-1

1.7 DO UNION'S ASSET CONDITION ASSESSMENT INFORMATION AND INVESTMENT PLANNING PROCESS APPROPRIATELY ADDRESS THE CONDITION OF THE DISTRIBUTION SYSTEM ASSETS AND SUPPORT THE OM&A AND CAPITAL EXPENDITURES PROPOSED FOR THE TEST YEAR?

(Complete Settlement)

For the purpose of settlement, the parties accept that Union's Asset Condition Assessment Information and Investment Planning Process appropriately address the condition of the distribution system assets and support the revised OM&A and capital expenditures proposed for the test year.

Evidence References: B1/T4, B1/T5, B1/T6, J.B-1-2-3, J.B-1-2-4, J.B-4-1-4, J.B-4-1-10

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit G1, Tab 1, Page 14 5(iii)

a) Why has Union decided that for maintenance of equipment on customer premises the costs are primarily related to customer station maintenance and a time based allocation is no longer appropriate?

b) Please provide details -amount of costs before and after the change.

c) Reconcile to Appendix B.

Response:

a) The internal work orders mapped to Distribution Maintenance - Equipment on Customer Premises primarily relate to customer station maintenance. The Board-approved cost allocation methodology allocates equipment on customer premises maintenance costs to general service customers in Union South based on service call time and general service customers in Union North based on a historic allocator. There are no maintenance costs related to equipment on customer premises allocated to contract rate customers, despite contract rate customers having customer stations requiring maintenance.

   Union is proposing to allocate these maintenance costs to both general service and contract rate customers in Union South and Union North in proportion to the allocation of customer stations plant. An allocation of maintenance costs based on the allocation of customer stations plant better reflects cost incurrence than a time-based allocation.

b) Please see Attachment 1.

c) Please see Attachment 1 (column c) and J.G-1-3-1 Attachment 1. J.G-1-3-1 includes the updated Revenue Requirement Impact to reflect the cost allocation study filed on March 27, 2012.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit G1, Tab 1, pages 8-11

Please confirm that no costs incurred for the new ex-franchise transportation services have been allocated to any in-franchise rate class in Union's South or North delivery areas. If this cannot be confirmed, please provide details to the costs allocated to these in-franchise rate classes.

Response:

Confirmed. No costs incurred for the new ex-franchise transportation services have been allocated to any in-franchise rate class in Union's South or North delivery areas.

The costs associated with C1 Dawn to Dawn-TCPL and C1 Dawn to Dawn-Vector firm transportation services have been directly assigned to the C1 rate class. The costs associated with the F24-T transportation service have been directly assigned to the M12 rate class.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit G3, Tab 1, Schedule 1, pages 14-15, Updated

a) Please separate out from the total Dawn Trafalgar Easterly costs any costs associated with the Parkway Station metering and compression and Kirkwall Station metering in the 2013 revenue requirement.

b) Does Union believe that costs for the Parkway Station metering and compression and Kirkwall Station metering should be allocated on the same basis as other Dawn Trafalgar Easterly costs? Please explain.

c) What is the impact on in-franchise customers (South and/or North) of a compression failure at Parkway?

d) What is the impact on ex-franchise customers of a compression failure at Parkway?

Response:

a) The approximate 2013 revenue requirement associated with the Parkway Station metering and compression and Kirkwall Station metering is $22.5 million.

b) Please see the response at Exhibit J.G-1-1-2 part b).

c) A compressor failure at Parkway would directly impact any customers served by Parkway discharge, and would have no effect on volumes up to and including Parkway suction. Following a compressor failure at Parkway, Union would immediately call all available interruptions to volumes supplied by Parkway discharge. The remaining shortfall would be allocated across all customers served by Parkway discharge, both in-franchise and ex-franchise. No customers west of Parkway, including those served by Parkway suction volumes (Parkway (Consumers) and Lisgar), would be impacted by a compressor failure at Parkway. Union expects that on a design day regional gas flow would be significantly impacted by a compressor failure at Parkway without loss of Critical Unit coverage.

d) Please see response at part c) above.

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

UNION'S 2013 RATE REBASING APPLICATION: STORAGE AND TRANSPORTATION ISSUES

EB-2011-0210

Prepared for

Canadian Manufacturers & Exporters (CME)
Consumers Council of Canada (CCC)
The Corporation of the City of Kitchener (CCK)
Federation of Rental-housing Providers of Ontario (FRPO)

By

John A. Rosenkranz

May 16, 2012

UNION'S 2013 RATE REBASING APPLICATION:
STORAGE AND TRANSPORTATION ISSUES

EB-2011-0210

Prepared by
John A. Rosenkranz

CME, CCC, CCK, and FRPO requested a review of Union's 2013 rate rebasing application as it pertains to Union's allocation of costs for its transportation and storage operations. I was asked to consider whether Union's proposed allocation of Dawn-Trafalgar transmission system costs to in-franchise and ex-franchise services is reasonable given the current characteristics and utilization of these facilities, and whether Union's allocation of revenues and costs between its utility and non-utility storage operations is consistent with Ontario Energy Board decisions. This report describes the results of that investigation. The findings and recommendations address four main topics:

- Union's allocation of Parkway Station costs
- Allocation of costs to Union's non-utility storage operation
- Union's obligation to optimize utility storage assets
- Deferral Account No. 179-70

A. Parkway Station Costs

Cost Allocation

In Union's cost allocation study, the costs of transporting gas on the Dawn-Parkway transmission system are divided into two categories: (1) the cost of the compressors needed to move gas from the Dawn Hub into the Dawn-Parkway system (Dawn Station costs); and (2) all remaining costs (Dawn-Trafalgar Easterly costs). Dawn-Trafalgar Easterly costs include Union's transmission pipelines, the compressors at Lobo, Bright, and Parkway, and the metering facilities at Kirkwall and Parkway. Parkway Station costs are allocated to rate classes based on design day demand, while Dawn-Trafalgar Easterly costs are allocated using a distance-based "commodity-kilometres" methodology.

Recommendation 1: Parkway Station costs should be separated from the other Dawn-Trafalgar Easterly transmission costs, and allocated to rate classes based on design day flow requirements.

Union both delivers gas and receives gas at Parkway, but the predominant direction of physical flow is from Union Gas to TCPL and Enbridge. The metering and compression facilities at Parkway Station are therefore designed to meet Union's design day requirement to export gas from the Union Gas system into the TCPL and Enbridge systems. Metering costs are a function of design day demand, and are not affected by the distance gas travels on the Dawn-Parkway system before reaching the Parkway Station. Compression horsepower at Parkway is determined by Union's peak day requirements to deliver gas into TCPL. Union's metering and compression assets at Parkway are not used to transport or deliver natural gas to any of the upstream in-franchise markets that are connected to the Dawn-Parkway transmission system. For all of these reasons, the Parkway Station costs should be separated from the remaining Dawn-Trafalgar Easterly transmission costs, and allocated to rate classes on the basis of design day requirements. This treatment of Parkway Station costs would better reflect cost causation when compared to Union's existing methodology, and would be consistent with the way that Union Gas currently allocates Dawn Station costs.

Allocating Parkway Station costs using the methodology recommended here would lower in-franchise costs by approximately $1.6 million per year (see Attachment 2).

<u>M12 Service Rate Design</u>

Recommendation 2: Parkway costs should be recovered from all services that utilize Parkway as a receipt or delivery point.

Once Parkway Station costs have been separated in the cost allocation, these costs should be recovered from those services that use the Parkway facilities. The rates for these services should reflect the shipper's maximum daily use of Parkway compression and/or metering.

Recommendation 3: Union should create a non-export M12 service that can be used by in-franchise customers to meet an obligated delivery requirement at Parkway.

The rates for services that do not use Parkway facilities, such as the existing Dawn-Kirkwall service, should not include Parkway Station costs. In addition, if Union continues to require in-franchise customers to make obligated deliveries at Parkway, Union should offer a "non-export" M12 service that Union South customers located upstream of Parkway could use to meet this obligation. This service would be based on the same allocation of Dawn-Trafalgar Easterly Costs as the standard Dawn-Parkway M12 service, but would exclude Parkway Station costs. Shippers would be able to use the non-export service to deliver gas to Union, but would not have rights to deliver gas to TCPL or Enbridge.

B. Non-Utility Storage Costs

In the NGEIR Decision[1], the Board decided to forbear from regulating rates or approving contracts for Union's ex-franchise storage services.[2] Union could continue to run an integrated storage operation, but the costs of existing storage assets would be divided between the "utility assets" required to serve in-franchise customers, and "non-utility assets". Only utility storage asset costs are included in Union's regulated ratebase and revenue requirement.

In the EB-2011-0038 decision, the Board approved Union's methodology to separate storage plant using storage space and deliverability factors from Union's 2007 rate case. This one-time separation, which is deemed to have occurred at the end of 2006, removed 37.7% of the existing storage plant from the utility ratebase. Union's pre-NGEIR "legacy" storage assets include company-owned storage pools, storage lines, compression, the transmission pipelines connecting Union's storage pools to the Dawn Hub, third party storage service, and third party transportation service to transport gas from third party storage to Dawn.

Neither the NGEIR Decision nor the EB-2011-0038 decision defined how additions and retirements of legacy storage assets would affect utility storage plant, or approve a methodology to allocate operating and maintenance costs to non-utility storage. Since this

[1] EB-2005-0551, Decision with Reasons, November 7, 2006.
[2] NGEIR Decision, p. 74.

EVIDENCE OF J. ROSENKRANZ ON BEHALF OF CME, CCC, CCK, & FRPO

Answer to Interrogatory 1 from Energy Probe

Ref: Written Evidence of John A. Rosenkranz, Page 3, Line 14

Preamble: "For all of these reasons, the Parkway Station costs should be separated from the remaining Dawn-Trafalgar Easterly transmission costs, and allocated to rate classes on the basis of design day requirements. This treatment of Parkway Station costs would better reflect cost causation when compared to Union's existing methodology, and would be consistent with the way that Union Gas currently allocates Dawn Station costs.

Allocating Parkway Station costs using the methodology recommended here would lower in-franchise costs by approximately $1.6 million per year (see Attachment 2)."

a) Please provide the Impact of Recommendations 1 and 2 on an in-franchise rate class basis.
b) Please estimate the annual impact on Enbridge customers.
c) Assuming the Parkway West Capital Project proceeds at a gross cost of $215 million please estimate the annual revenue requirement in 2014 for Parkway Station.
d) Would/should the costs of the PW Project also be allocated as proposed in the evidence? Please discuss.
e) Please provide a version of Attachment 2 post in-service (2014) of the Parkway West Project.

Response:

a) An estimate of the impact by rate class is as follows:

Rate Schedule		*Impact ($000)*
Gen. Service Small Volume	*M1*	*-935*
Gen. Service Large Volume	*M2*	*-314*
Firm Contract	*M4*	*-91*
Interruptible Contract - Firm	*M5*	*-1*
Special Large Volume Contract Firm	*M7*	*-42*
Large Wholesale Service	*M9*	*-15*
Small Wholesale Service	*M10*	*-1*
Transportation Service - Firm	*T1*	*-338*
Wholesale Transportation Service	*T3*	*-106*
North and East	*R1 - R100*	*142*

b) Enbridge Gas Distribution currently holds M12 contracts that provide for 2,157,173 GJ/day to be delivered at Parkway (J.D-14-16-7). This is approximately 51% of Union's the total ex-franchise demand of 4,194,375 GJ/day at the Parkway Station (Exhibit C1, Tab 3, Schedules 3 & 4). If the total impact on M12 rates is approximately $1.6 million, Enbridge Gas Distribution M12 service costs would increase by roughly $820,000 per year.

c) Union estimates the first full year operating cost for depreciation, allowed return and taxes for the Parkway West Project to be approximately $16.4 million (Exhibit J.B-1-7-8). This estimate includes most of the increase in the revenue requirement.

d) Yes. If the purpose of the Parkway West Project is to improve the reliability of the existing Parkway Station, the Parkway West Project costs should be rolled into the existing Parkway Station costs and allocated to the customers that use the Parkway Station based on design day demand.

e) Please see the Attachment.

Attachment

PARKWAY STATION COST SEPARATION EXAMPLE
With Parkway West Costs

		Hypothetical Revenue Requirement ($000)		
		Dawn-Trafalgar East	Parkway Station	Total
	Union Application, Plus Parkway West Costs			
1	M12	140,765		140,765
2	In-Franchise	27,325		27,325
3	Total	168,090		168,090
	Parkway Station Separation with Parkway West Costs			
4	M12	113,285	30,782	144,067
5	In-Franchise	22,096	1,927	24,023
6	Total	135,381	32,709	168,090
	Difference			
7	M12			3,302
8	In-Franchise			-3,302

Notes

Line 3: *Assumed Parkway West Project cost of service of $16.4 million.*

Lines 4 & 5: *Dawn-Trafalgar East costs allocated to M12 and In-franchise services using DTTRANS allocation factor.*
Parkway Station costs allocated to M12 and In-franchise services using estimated Parkway demand.

Line 6: *Parkway Station costs separated from Dawn-Trafalgar East based on net plant.*

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-Housing Providers of Ontario ("FRPO")

Ref: Exhibit H1, Tab 1, page 51

Union co-sponsored evidence by Mr. Feingold in the TCPL 2012 and 2013 Mainline Tolls proceeding that addressed the classification of transmission costs as distance-based or non-distance based. According to Mr. Feingold:
"My experience is that while there is some latitude in determining if a cost is distance related, the classification is neither arbitrary nor discretionary. Rather, a thorough analysis of the cost is required to determine if a cost is or is not distance-related."

a) Has Union done a cost study of the type described by Mr. Feingold for the Dawn-Trafalgar transmission system to determine which costs are distance-related and which costs are not distance-related? If so, what portion of the Dawn-Trafalgar Easterly costs was found to be not distance-related?

b) If Union has not done such a cost study, please explain why Union considers it appropriate to design transportation rates for C1 services using the Dawn-Trafalgar system that have a Kirkwall receipt point on the basis that all of the costs of providing these services are distance-related.

Response:

a) Union prepared a cost allocation study as directed by the Board in its E.B.R.O. 486 Decision. In October 1995 R.J. Rudden Associates Inc ("RJRA") was retained by Union to undertake an in-depth and comprehensive review of cost allocation and rate design for services offered on the Dawn-Trafalgar transmission system.

   This study was meant to ensure that there is no cross subsidy among rate classes which use the Dawn-Trafalgar system and was presented in Union's 1997 rate case. In its E.B.R.O. 493/494 Decision, the Board-approved Union's cost allocation and rate design.

   Based on the RJRA review, Union's distance-based cost allocation methodology of Dawn-Trafalgar system transmission costs was found to be appropriate for the following reasons:

   i) "Dawn-Trafalgar transmission system has a distinct west to east orientation".
   ii) "There is a general need to transport M12 gas volumes over longer distances during the winter".

iii) "The location of customer demands imposed on the Dawn-Trafalgar transmission system has an impact on the amount of system capacity provided by facilities".

b) C1 easterly Dawn-Trafalgar rates are equivalent to M12 easterly Dawn-Trafalgar rates. C1 Dawn-Trafalgar service, however, is not subject to the Yearly Commodity Required (YCR)/Yearly Commodity Revenue Required (YCRR) true-up.

   C1 westerly transportation rates on the Dawn-Trafalgar system (Parkway to Kirkwall/Dawn and Kirkwall to Dawn) are based on Union's M12 easterly transportation rates excluding Dawn compression. C1 westerly transportation rates also reflect the expected number of days of westerly flow.

UNION GAS LIMITED

Undertaking of Mr. Tetreault
To Mr. Aiken

Please file update to J.H-1-14-2, Attachment 1.

Please see the Attachment.

Annual General Service Delivery Bill Impacts - Union South
of Proposed 2014 Change in Annual Volume Breakpoint (1)

	2013 Proposed with Annual Volume Breakpoint of 50,000 m^3		2014 Proposed with Annual Volume Breakpoint of 5,000 m^3		Bill Impacts	
Annual Volume	Rate M1	Rate M2	Rate M1	Rate M2	$	%
1,800	323.12		324.97		1.85	0.6%
2,200	337.57		339.58		2.01	0.6%
2,600	351.94		354.09		2.14	0.6%
3,000	366.20		368.47		2.27	0.6%
5,000	436.44		439.21		2.77	0.6%
5,001	436.47			585.59	149.12	34.2%
6,000	470.93			618.57	147.64	31.3%
7,000	505.38			651.36	145.98	28.9%
10,000	608.53			749.11	140.58	23.1%
20,000	948.89			1,073.28	124.39	13.1%
30,000	1,288.78			1,396.41	107.64	8.4%
50,000	1,968.54			2,038.38	69.85	3.5%
60,000		3,252.26		2,355.05	(897.21)	-27.6%
70,000		3,642.17		2,671.24	(970.93)	-26.7%
80,000		4,031.07		2,987.00	(1,044.07)	-25.9%
100,000		4,804.38		3,616.58	(1,187.80)	-24.7%
200,000		8,521.82		6,720.25	(1,801.58)	-21.1%
300,000		12,148.30		9,797.39	(2,350.91)	-19.4%
500,000		19,308.57		15,922.58	(3,385.98)	-17.5%

Notes:

(1) Grey shading represents all changes when compared to Exhibit H1, Tab 1, Table 12, page 28 of the July 13, 2012 Settlement filing.

UNION GAS LIMITED

Undertaking of Mr. Shepherd
To Mr. Tetreault

Please provide the costs allocated to M1, M2, 01, and 010 for 2013 and 2014; and what adjustments were made to get from one to the other.

Please see the Attachment for the re-allocation of 2014 general service delivery-related costs. The methodology used to re-allocate delivery-related costs between Rate 01 and Rate 10 and Rate M1 and Rate M2 is consistent with the methodology approved by the Board in 2007 to split the Rate M2 rate class into Rate M1 and Rate M2.

The Attachment, page 1 summarizes the general service delivery-related costs in 2013 and 2014. As shown at lines 3 and 6, columns (c) and (f), total general service delivery-related costs remain unchanged in 2013 and 2014 by operating area.

The Attachment, page 2 summarizes the re-allocation of customer-related costs for Rate 01 and Rate 10 and Rate M1 and Rate M2 based on the proposed 2014 annual volume breakpoint of 5,000 m^3.

Customer-related costs are re-allocated between Rate 01 and Rate 10 and Rate M1 and Rate M2 using a weighted number of customers based on 2010 actual customers identified at Exhibit H1, Tab 1, Updated, Tables 5 and 6. The weighted number of customers is derived by applying weights to the actual customer counts to ensure a proper allocation of costs. The weights used are 1.0 for residential, 1.5 for commercial and 2.0 for industrial. Based on the weighted number of customers by rate class, the customer-related costs are allocated between Rate 01 and Rate 10 and Rate M1 and Rate M2 as shown at lines 1 to 18.

The Attachment, page 3 summarizes the re-allocation of the remaining delivery-related costs for Rate 01 and Rate 10 and Rate M1 and Rate M2. The remaining delivery-related costs are re-allocated between rate classes by operating area based on 2010 actual volumes and the 5,000 m^3 annual volume breakpoint. The allocation of the remaining delivery-related costs is shown at lines 1 to 6.

2013 and 2014 Delivery-related Costs
for Rate 01, Rate 10, Rate M1 and Rate M2

Line No.	Particulars ($000's)	Proposed 2013 General Service Revenue Requirement with Annual Volume breakpoint at 50,000 m^3				Proposed 2014 General Service Revenue Requirement with Annual Volume breakpoint at 5,000 m^3		
		Customer-Related		Other Delivery	Total	Customer-Related	Other Delivery	Total
		(a)		(b)	(c)	(d)	(e)	(f)
	Union North							
1	Rate 01	117,795	(1)	47,066	164,861	111,039	35,211	146,250
2	Rate 10	3,770	(2)	15,476	19,246	10,527	27,330	37,857
3	Total- Union North	121,565		62,542	184,107	121,566	62,542	184,107
	Union South							
4	Rate M1	282,101	(3)	99,137	381,238	269,086	75,911	344,998
5	Rate M2	8,992	(4)	36,461	45,453	22,006	59,687	81,693
6	Total - Union South	291,093		135,598	426,691	291,093	135,598	426,691

Notes:
(1) Exhibit H3, Tab 1, Schedule 2, page 1, line 1, column (e).
(2) Exhibit H3, Tab 1, Schedule 2, page 2, line 1, column (e).
(3) Exhibit H3, Tab 1, Schedule 2, page 5, line 1, column (e).
(4) Exhibit H3, Tab 1, Schedule 2, page 5, line 11, column (e).

2014 Allocation of Customer-related Costs
for Rate 01, Rate 10, Rate M1 and Rate M2
based on an annual volume breakpoint of 5,000 m^3

Line No.	Particulars	2010 Actual Number of Customers at 50,000 m^3 breakpoint	2010 Actual Number of Customers at 5,000 m^3 breakpoint	Weighting	Weighted Number of Customers	Percentage	Customer-Related Costs ($000's)	General Service Allocated Costs Attachment Reference
		(a)	(b)	(c)	(d)= (b) * (c)	(e) based on (d)	(f)	(g)
	Union North							
	Rate 01							
1	Residential	272,963	267,742	1.0	267,742			
2	Commercial	26,413	13,498	1.5	20,247			
3	Industrial	33	6	2.0	12			
4	Total	299,409 (1)	281,246 (3)		288,001	91.3%	111,039 (9)	
	Rate 10							
5	Residential	4	5,225	1.0	5,225			
6	Commercial	1,619	14,534	1.5	21,801			
7	Industrial	112	139	2.0	278			
8	Total	1,735 (2)	19,898 (4)		27,304	8.7%	10,527 (10)	
9	Total - Union North	301,144	301,144		315,305	100.0%	121,565	Page 1, line 3, column(a)
	Union South							
	Rate M1							
10	Residential	915,184	898,064	1.0	898,064			
11	Commercial	73,418	42,241	1.5	63,362			
12	Industrial	3,982	1,432	2.0	2,864			
13	Total	992,584 (5)	941,737 (7)		964,290	92.4%	269,086 (11)	
	Rate M2							
14	Residential	41	17,161	1.0	17,161			
15	Commercial	5,078	36,255	1.5	54,383			
16	Industrial	1,109	3,659	2.0	7,318			
17	Total	6,228 (6)	57,075 (8)		78,862	7.6%	22,006 (12)	
18	Total - Union South	998,812	998,812		1,043,151	100.0%	291,093	Page 1, line 6, column (a)

Notes:
(1) Exhibit H1, Tab 1, Page 18, Table 6, lines 13-16, column (b).
(2) Exhibit H1, Tab 1, Page 18, Table 6, lines 13-16, column (e).
(3) Exhibit H1, Tab 1, Page 18, Table 6, lines 5-8, column (b).
(4) Exhibit H1, Tab 1, Page 18, Table 6, lines 5-8, column (e).
(5) Exhibit H1, Tab 1, Page 16, Table 5, lines 13-16, column (b).
(6) Exhibit H1, Tab 1, Page 16, Table 5, lines 13-16, column (e).
(7) Exhibit H1, Tab 1, Page 16, Table 5. Rate M1 customers in column (b) above per Table 5, lines 5-8, column (b).
(8) Exhibit H1, Tab 1, Page 16, Table 5. Rate M2 customers in column (b) above per Table 5, lines 5-8, column (e).
(9) Rate 01 Customer-Related costs at the 5,000 m^3 annual volume breakpoint: 91.3% * 121,565 = $111,039.
(10) Rate 10 Customer-Related costs at the 5,000 m^3 annual volume breakpoint: 8.7% * 121,565 = $10,527.
(11) Rate M1 Customer-Related costs at the 5,000 m^3 annual volume breakpoint: 92.4% * 291,093 = $269,086.
(12) Rate M2 Customer-Related costs at the 5,000 m^3 annual volume breakpoint: 7.6% * 291,093 = $22,006.

2014 Allocation of Other Delivery-related Costs
for Rate 01, Rate 10, Rate M1 amd Rate M2
based on an annual volume breakpoint fo 5,000 m^3

Line No.	Particulars	2010 Actual Annual Volume (m^3) at 50,000 m^3 breakpoint (a)	2010 Actual Annual Volume (m^3) at 5,000 m^3 breakpoint (b)	Percentage (c) based on (b)	Other Delivery Costs ($000's) (d)	General Service Allocated Costs Attachment Reference (e)
	Union North					
1	Rate 01	837,395,960 (1)	609,371,320 (3)	56.3%	35,212 (9)	
2	Rate 10	244,955,407 (2)	472,980,046 (4)	43.7%	27,330 (10)	
3	Total - Union North	1,082,351,367	1,082,351,367	100.0%	62,542	Page 1, line 3, column (b)
	Union South					
4	Rate M1	2,679,588,627 (5)	2,043,883,921 (7)	56.0%	75,911 (11)	
5	Rate M2	971,362,682 (6)	1,607,037,388 (8)	44.0%	59,687 (12)	
6	Total - Union South	3,650,951,309	3,650,921,309	100.0%	135,598	Page 1, line 6, column (b)

Notes:
(1) Exhibit H1, Tab 1, Page 18, Table 6, lines 13-16, column (a).
(2) Exhibit H1, Tab 1, Page 18, Table 6, lines 13-16, column (d).
(3) Exhibit H1, Tab 1, Page 18, Table 6, lines 5-8, column (a).
(4) Exhibit H1, Tab 1, Page 18, Table 6, lines 5-8, column (d).
(5) Exhibit H1, Tab 1, Page 16, Table 5, lines 13-16, column (a).
(6) Exhibit H1, Tab 1, Page 16, Table 5, lines 13-16, column (d).
(7) Exhibit H1, Tab 1, Page 16, Table 5, lines 5-8, column (a).
(8) Exhibit H1, Tab 1, Page 16, Table 5, lines 5-8, column (d).
(9) Rate 01 Other Delivery-related costs at the 5,000 m^3 annual volume breakpoint: 56.3% * 62,542 = $35,212.
(10) Rate 10 Other Delivery-related costs at the 5,000 m^3 annual volume breakpoint: 43.7% * 62,542 = $27,330.
(11) Rate M1 Other Delivery-related costs at the 5,000 m^3 annual volume breakpoint: 56.0% *135,598 = $75,911.
(12) Rate M2 Other Delivery-related costs at the 5,000 m^3 annual volume breakpoint: 44.0% *135,598 = $59,687.

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME:	**12**	
DATE:	**July 30, 2012**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

MR. TETREAULT: Mr. Aiken, with the July update, we did include a new schedule in Exhibit H3, and -- that performs that reconciliation. And that schedule is H3, tab 12, schedule 1. That was a new tab with the July filing.

MR. AIKEN: Okay, thank you. I'm looking at it on the screen. And where do I find the 17.955 million?

MR. TETREAULT: You would see that on line 19.

MR. AIKEN: Okay.

MR. TETREAULT: And that number will tie back to the settlement schedules we were just referring to.

MR. AIKEN: Yeah, okay. Thank you.

Moving on to some generic questions, at a high level, does Union Gas allocate demand-related or capacity-related costs between customers in different rate classes based on peak day demands by rate class?

MR. TETREAULT: Yes, we do.

MR. AIKEN: What is the difference, if any, between peak day and design day?

MR. TETREAULT: I consider them to be the same, Mr. Aiken, just different terminology, I think, depending on whether you're speaking to an operational group or, you know, perhaps a cost allocation group. Same terms.

MR. AIKEN: And the use of the peak day, is that why residential customers, for example, generally get allocated more demand-related costs than do large contract customers relative to the annual volume comparison between those two classes?

In other words, they have a lower load factor than most large industrial customers, so if their volumes were the same, their peak would be higher and, therefore, they get higher demand costs allocated to them?

MR. TETREAULT: Yes, that's correct.

MR. AIKEN: And then at the same high level, what costs are included as customer-related costs in the cost allocation study?

MR. TETREAULT: Those would generally be costs associated with attaching customers to the system and maintaining their attachment to the system over time.

MR. AIKEN: Does it include billing and meter reading costs?

MR. TETREAULT: Yes, it does.

MR. AIKEN: In terms of assets, do they -- to do the costs include meters, regulators and service lines?

MR. TETREAULT: Yes.

MR. AIKEN: Okay, thank you. Now, do these types of costs on a per-customer basis generally increase as the customer size goes up to reflect higher cost meters, regulators, et cetera, and more complexity in the billing?

MR. TETREAULT: Yes, that's fair.

MS. O'CONNOR: Okay. Now I'm going to move on to rate design.

Am I correct that Union is not proposing any rate design changes from those proposed in the original evidence and your update?

MR. TETREAULT: That's correct.

MR. AIKEN: So I would be correct that the updated

And for the 14 additional Rate 10 customers, the $70 charge would give you additional revenue of $11,670, subject to check.

So that would be the additional revenue if the charge was set the same as the monthly charge.

MR. AIKEN: Instead of adding the charge in the north to harmonize with the south, has Union considered dropping the charge in the south to harmonize with the north and extending your policy from the centre days?

MR. TETREAULT: No, we did not. We did not consider that, Mr. Aiken. We were comfortable with the difference in policy between north and south in this area.

MR. AIKEN: Would you take it subject to check that if you did drop the charge in the south, that it would result in a reduction in revenues of approximately $300,000?

MR. TETREAULT: I can take that subject to check.

MR. AIKEN: I'm moving on now to the 2014 rate design proposals. And I note that in response to JT2.18, at pages 21 -- sorry, pages 20 and 21 of the compendium, Union arrived at the $35 customer charge for rates 10 and M2 by taking the mid-point of the monthly customer charges -- this is actually shown on the top of page 21 of the compendium -- by taking the mid-point of the monthly customer charges required to recover all customer-related costs.

So based on table 1 on page 21 of the compendium, does this mean that Union will be recovering more than 100 percent of the customer-related costs for the M2 rate

MR. PANKRAC: Yes.

MR. AIKEN: So if that were reduced to 100 percent, which would be at roughly the $30, how would that impact your fixed cost percentage that you noted earlier?

MR. TETREAULT: It would increase slightly, by approximately $3.5 million, the volumetric recovery of fixed costs.

MR. AIKEN: All right. Has Union considered any rate mitigation measures for the customers that you propose to move from Rate 1 to M2, given the 34 percent increase for the small ones, anyways?

MR. TETREAULT: No, we have not, Mr. Aiken. As you know, our rate design proposals in total are revenue neutral, and the number of customers that are impacted adversely in some way by our rate design proposals in general service is a very small percentage of the overall customer base.

I believe it's in the neighbourhood of 58 to 60,000 customers out of a general service customer base of approximately 1.4 million, so somewhere in the order of, I'll say, 4 percent of the total customer base.

MR. AIKEN: Okay. Now I've got some general questions on the proposals for 2014. So if we go back to page 23 of the LPMA compendium, this is attachment 1 to J.H-1-14-2.

This schedule shows that, under your proposal, a customer using 5,000 cubic metres under rate M1 would pay $451.30, while a customer consuming one cubic metre more, and therefore in rate 2, would be paying $597.10.

increase, do you consider that impact to be a smooth transition between rates M1 and M2?

MR. TETREAULT: Overall, we do consider the continuity between classes to be appropriate. And, again, we're balancing continuum with a number of other considerations, largely, the fixed cost recovery in a monthly customer charge.

So, on balance, we are comfortable with the change we're seeing in '14, under the understanding, of course, that in aggregate, the proposals are revenue neutral and only impact a small portion of total M1/M2 customers.

MR. AIKEN: If we now go to page 24 of the compendium, this is attachment 1 to J.H-5-2-1. Am I correct that this shows that a large M2 customer that would qualify for an M4 contract could end up paying significantly more or less than under the M2 rate in 2014?

MR. PANKRAC: Yes. In this analysis, you can see that the crossover for a comparable customer between M2 and M4 occurs somewhere between the 40 and 50 percent load factor. I think I calculated that it's around 48 or 49 percent, where in fact there would be price equivalence.

MR. AIKEN: Now, we see that the rate impacts range from a drop of 16.6 percent to an increase of 9.5 percent in those four examples provided there.

MR. PANKRAC: Yes.

MR. AIKEN: Does Union have the same magnitude of changes in rates between, for example, M4 and M7, or T1 and T2, as the results based on Union's proposals for M1 and factor sensitivity, is that in fact it is the load factor, it is the efficiency that is producing those economies or those reductions at the 57.1 percent load factor and at the 49.5 percent load factor in this illustration.

And so what we do is we do say that the proper behaviour, that as load factor increases, as efficiency increases, you would expect the average unit price decrease.

MR. AIKEN: How does Union communicate to customers that they qualify for a contract rate? In other words, how do they advise an M2 customer that they may qualify to be an M4 customer?

MR. PANKRAC: That would be part of -- subject to approval, that would be part of our broad-based communication by a number of different tools, and also through a number of meetings with customers.

MR. AIKEN: Does Union advise customers that the M4 contract rate could end up costing them more than the non-contract M2 class?

MR. PANKRAC: Because it is really a function of how the customer selects their CD and their load factor, those things are very customer-specific. And so certainly to the extent that customers ask us, we do provide a comparison, and -- but really, at the end of the day, it is the customer's comfort level around whether he wants to pay in one rate structure or another.

MR. TETREAULT: Contract rate customers, Mr. Aiken, would typically have a sales rep or an account manager that they work with that's familiar with their business. So the account manager would typically be having those type of discussions with the contract rate customer.

MR. AIKEN: But if they're a large M2 customer, they're not a contract customer, at least not yet. So how do these large M2 customers become aware that they might qualify for a contract rate, and then, once they're aware of that, does Union advise them that in some cases it may actually cost them more to be an M4 customer?

In other words, does somebody -- an apartment building, for example, with a low load factor who has an annual volume that exceeds 350,000 cubic metres a year, but may have a poor load factor that could end up paying more under M4 than under M2?

MR. PANKRAC: Yes. There are two ways that we manage that. First of all, we have identified in our evidence that the number of customers, assuming our proposals are approved, that might be eligible for this is about 595 customers.

Those customers are managed by a separate billing system, and, in addition to that, what we have is we do have the communication tools to communicate that.

Our other way that we manage that is just because we have continued to maintain the 40 percent load factor, and so to the extent a customer does not have a 40 percent load factor, they would not be eligible for the M4 service in the first place.

And so between those two constraints, that really cuts down on the number of customers that would be in the situation that you identify, Mr. Aiken.

MR. AIKEN: Could you turn to page 2 of the attachment to JT2.27? This can be found at page 16 of the SEC compendium, Exhibit K10.5.

Now, you touched earlier on the number of customers this will impact. So am I correct that your proposal to change the volume breakpoint for the M1 and M2 customers, which is the group I'm concentrating on, will impact about 31,000 of the 78,000 commercial customers in Union south?

MR. PANKRAC: I'm just turning up another table, Mr. Aiken, just to confirm that.

So for Union south, at table 5 of our written evidence, at page 17, we identify that the number of customers, if we change the volume breakpoint, goes from -- in Union south, goes from about 6,000 to about 57,000. So I take that to be about 51,000, more or less.

MR. AIKEN: Okay. Well, if you look at the page that's up on the screen.

MR. PANKRAC: Yes.

MR. AIKEN: If you look at line 11.

MR. PANKRAC: Line 11? I have it.

MR. AIKEN: The first column shows 73,418 commercial M1 customers, and another -- at line 15, another 5,000 commercial M2. So that's a total of about 78,000 commercial customers in the south.

MR. PANKRAC: Mm-hm.

MR. AIKEN: Then the second column shows, under your with the numbers to be moved?

MR. PANKRAC: That's correct.

MR. AIKEN: Do you have any empirical evidence to support the relative difference in the weights? In particular, why is the industrial weight twice the residential weight, and why is the commercial weight the mid-point of the industrial and residential weights?

MR. PANKRAC: The empirical evidence we have is similar to the evidence we used when we did the 2007 rate split, which used those same weightings.

MR. AIKEN: And has evidence been filed in this proceeding, the evidence about these relative weights?

MR. PANKRAC: No.

MR. AIKEN: Would you undertake to file that information?

MR. SMITH: Sorry, just one moment.

[Witness panel confer]

MR. SMITH: Why don't we do this? We'll take a look at see what we have and -- when we filed it, and we'll refile it.

MS. HARE: Thank you.

MR. MILLAR: J12.2.

UNDERTAKING NO. J12.2: TO REFILE EVIDENCE RELATED TO RELATIVE WEIGHTINGS

MR. AIKEN: Would you agree that if you changed the relative weightings, there could be significant changes in the costs allocated between the 01 and 10 rate classes and between the M1 and M2 rate classes?

UNION GAS LIMITED

Undertaking of Mr. Pankrac
To Mr. Aiken

Please refile evidence related to relative weightings.

In Union's 2007 cost of service proceeding (EB-2005-0520), Union filed a report prepared by Navigant Consulting Inc. At page 29 of the report, Navigant stated:

> "The Average Weighted Customers factor is developed by applying weights to the actual customer counts to ensure a proper allocation of costs. The weights currently used by Union are 1.0 for residential, 1.5 for commercial, and 2.0 for industrial. NCI understands that Union is currently reviewing the appropriateness of these weights."

Union could not find any other 2007 source files related to the weightings.

For 2013 rates, Union used the historical weightings as used in 2007.

UNION GAS LIMITED

Undertaking of Mr. Pankrac
To Mr. Shepherd

Please provide the analysis done to show customers clustered near the average.

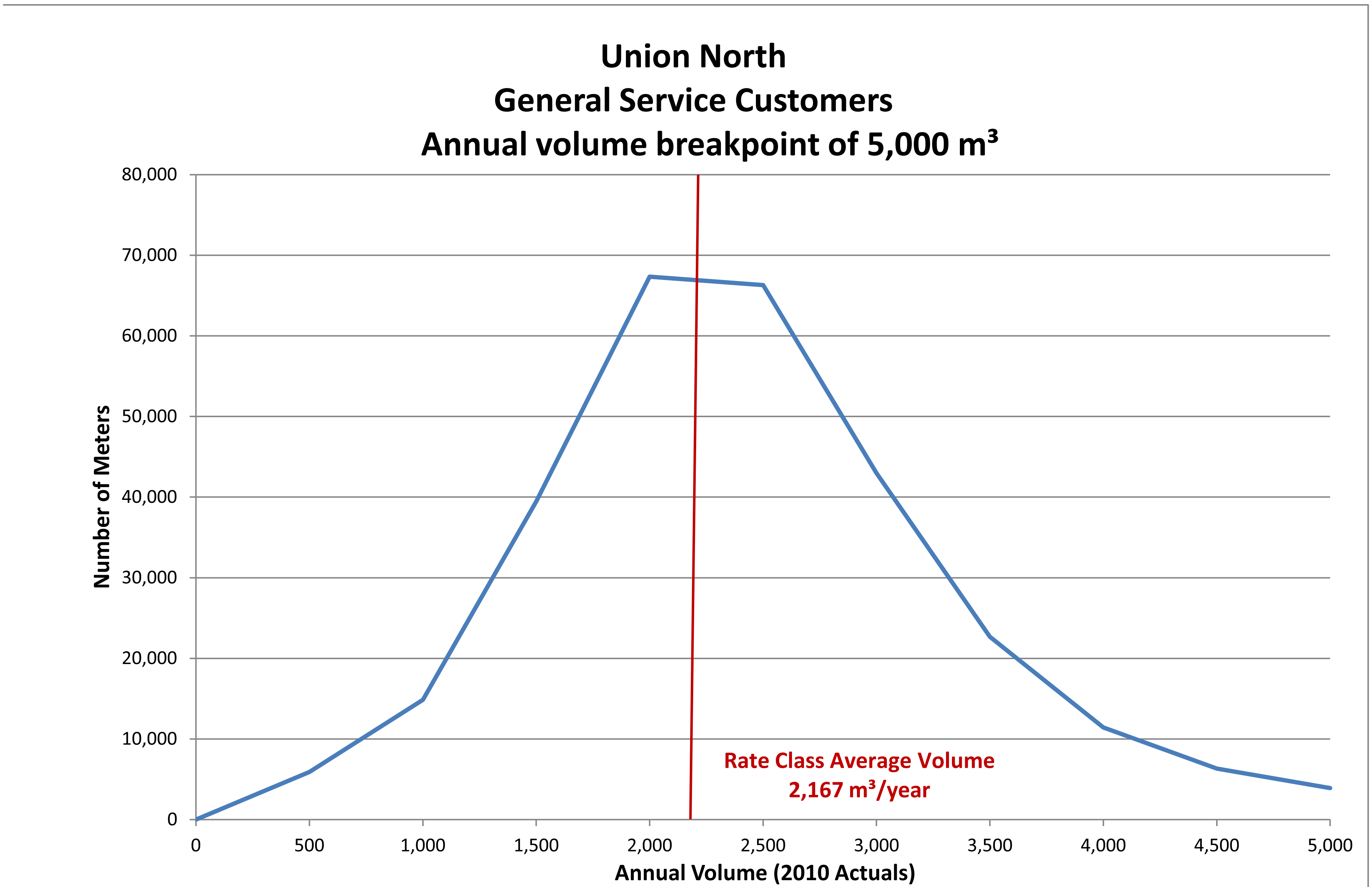
Please see Attachment 1 for Union North General Service Customers and Annual Volume Breakpoint of 5,000 m³.

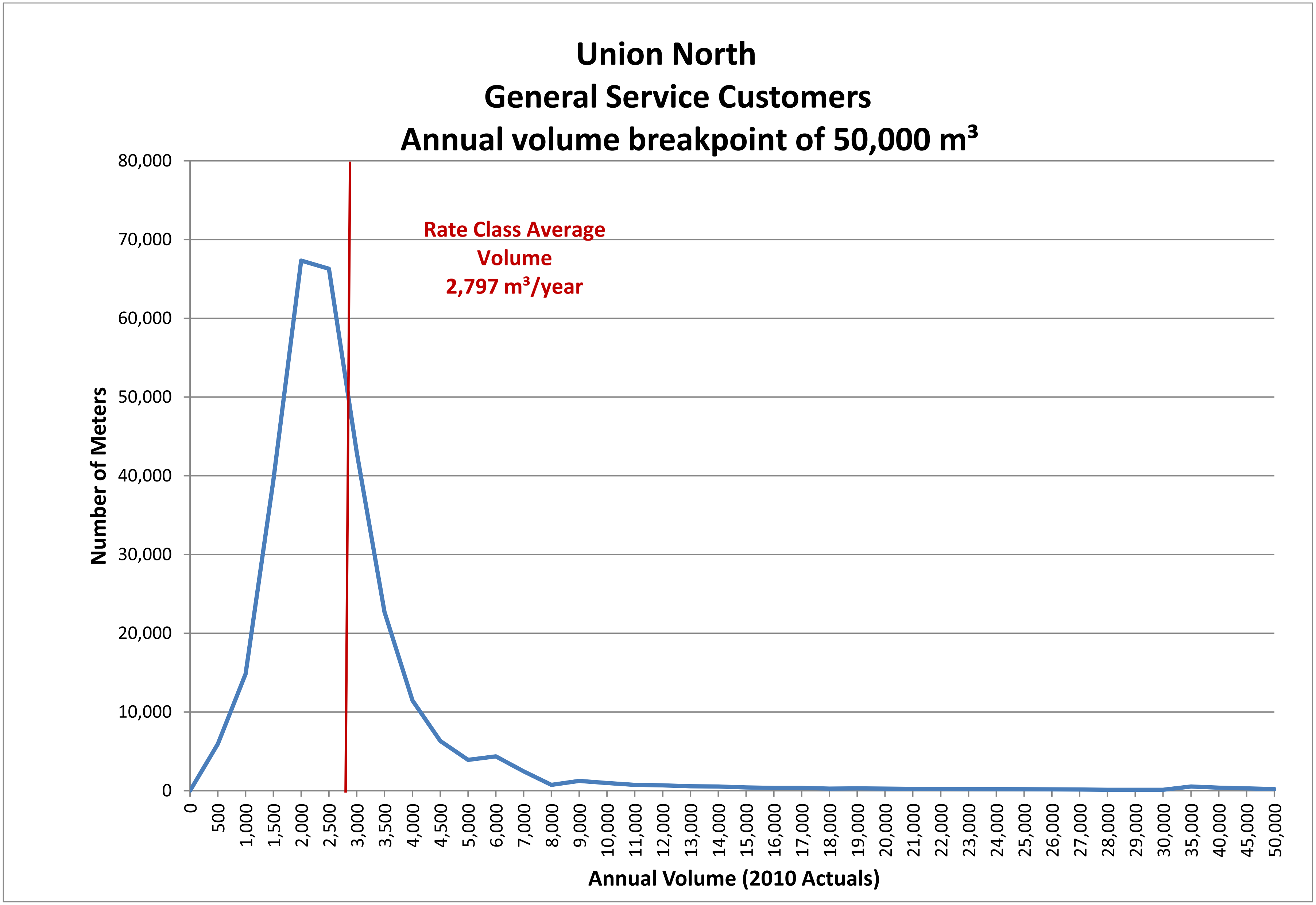
Please see Attachment 2 for Union North General Service Customers and Annual Volume Breakpoint of 50,000 m³.

Please see Attachment 3 for Union South General Service Customers Annual Volume Breakpoint of 5,000 m³.

Please see Attachment 4 for Union South General Service Customers Annual Volume Breakpoint of 50,000 m³.

The charts attached demonstrate that by moving to a 5,000 m³ breakpoint for both the North and South results in a more normal distribution of customers around the mean.


Union North
General Service Customers
Annual volume breakpoint of 5,000 m³
Number of Meters
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Rate Class Average Volume
2,167 m³/year
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
Annual Volume (2010 Actuals)


Union North
General Service Customers
Annual volume breakpoint of 50,000 m³
Rate Class Average
Volume
2,797 m³/year
Number of Meters
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
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24,000
25,000
26,000
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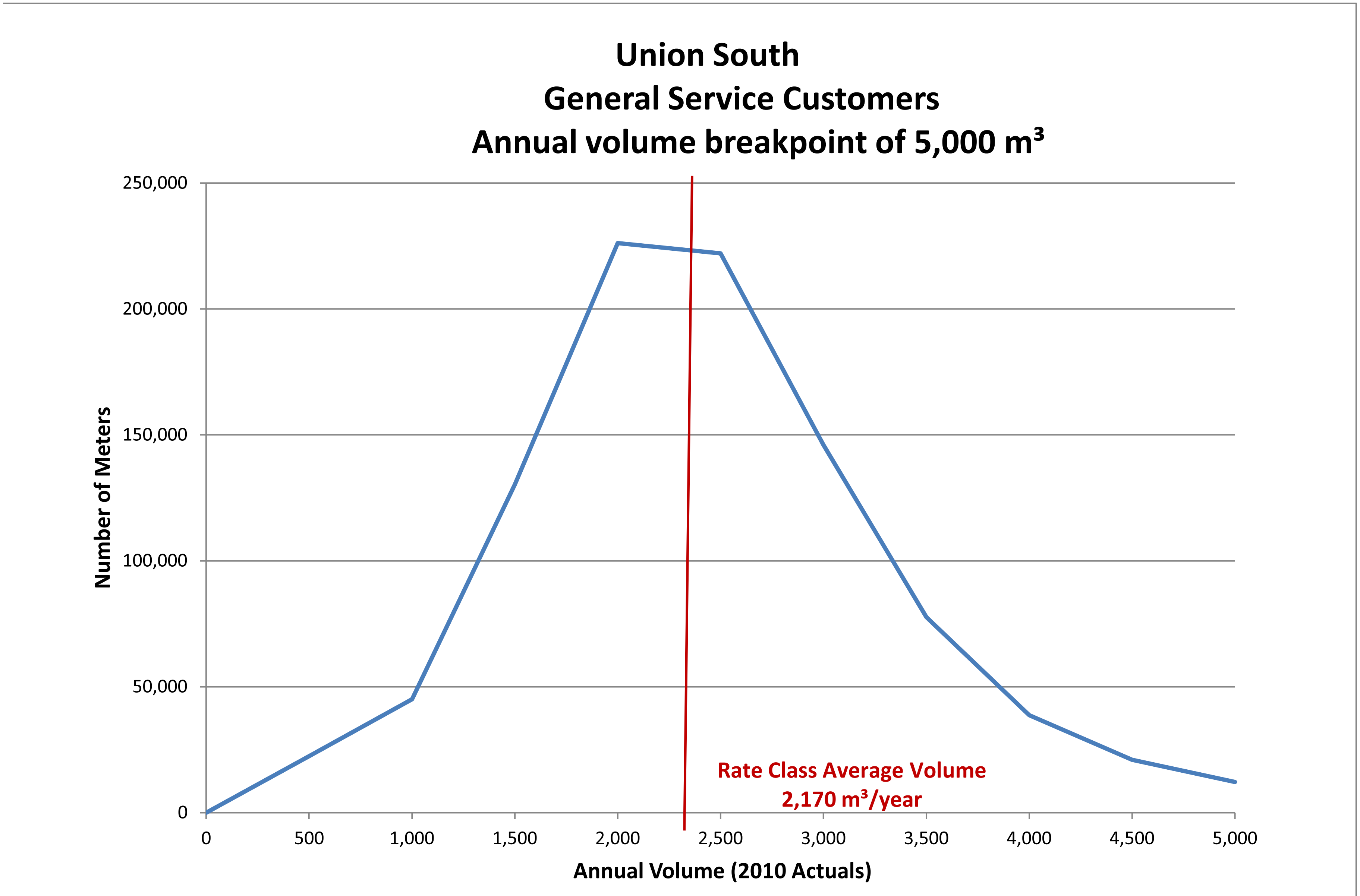
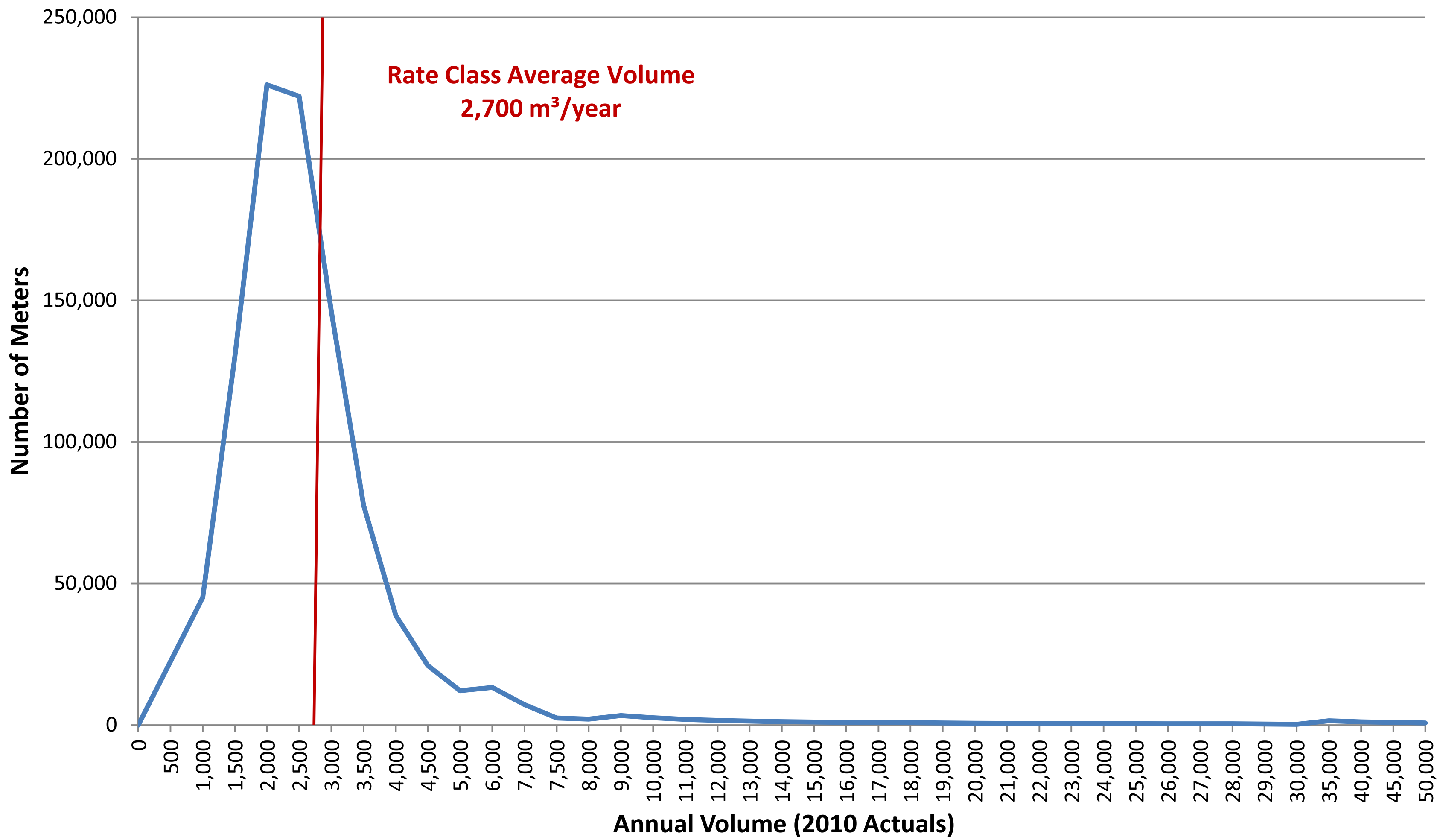
29,000
30,000
35,000
40,000
45,000
50,000
Annual Volume (2010 Actuals)


Union South
General Service Customers
Annual volume breakpoint of 5,000 m³
Number of Meters
250,000
200,000
150,000
100,000
50,000
0
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
Annual Volume (2010 Actuals)
Rate Class Average Volume
2,170 m³/year

Union South
General Service Customers
Annual volume breakpoint of 50,000 m³



Weighting of Customer Related Costs (Source Exhibit JT2.27)

WITH COMMERCIAL WEIGHT OF 1.0

	(a)	(b)	(c) = (a) x (b)	(d)	(e)	(f)	(g) = (e) - (f)
North	**Breakpoint 5,000 Customers**	**Weighting**	**Weighted Customers at 5,000 Breakpoint**	**Percentage**	**LPMA Cost Allocation**	**Union Cost Allocation**	**Difference**
01 - Residential	267,742	1.00	267,742				
01 - Commercial	13,498	1.00	13,498				
01 - Industrial	6	2.00	12				
Total 01	281,246		281,252	93.3%	$113,480	$111,039	$2,442
10 - Residential	5,225	1.00	5,225				
10 - Commercial	14,534	1.00	14,534				
10 - Industrial	139	2.00	278				
Total 10	19,898		20,037	6.7%	$8,085	$10,527	($2,442)
Total North	301,144		301,289		$121,565	$121,565	$0

South	**Breakpoint 5,000 Customers**	**Weighting**	**Weighted Customers at 5,000 Breakpoint**	**Percentage**	**LPMA Cost Allocation**	**Union Cost Allocation**	
M1 - Residential	898,064	1.00	898,064				
M1 - Commercial	42,241	1.00	42,241				
M1 - Industrial	1,432	2.00	2,864				
Total M1	941,737		943,169	94.0%	$273,482	$269,086	$4,396
M2 - Residential	17,161	1.00	17,161				
M2 - Commercial	36,255	1.00	36,255				
M2 - Industrial	3,659	2.00	7,318				
Total M2	57,075		60,734	6.0%	$17,611	$22,006	($4,396)
Total South	998,812		1,003,903		$291,093	$291,093	$0

UNION GAS LIMITED

Undertaking of Mr. Pankrac
To Mr. Aiken

Please provide an additional line item to J.H-1-15-2, Attachment 4 which shows volumetric related costs.

Please see the Attachment.

Union South General Service - 2014 Proposed Delivery
Customer, Demand and Commodity-related Costs by Rate Class

Line No.	Particulars ($000's)	Rate M1 (a)	Rate M2 (b)	Total (c) = (a+b)
1	Customer Related Costs (1)	269,086	22,006	291,092
2	Demand Related Costs (2)	76,763	60,356	137,119
3	Commodity Related Costs	1,799	1,414	3,213
4	Total Allocated Costs (line 1 + line 2 + line 3)	347,648	83,776	431,424

Notes:
(1) J.H-1-15-2, Attachment 4, line 1.
(2) J.H-1-15-2, Attachment 4, line 6.

Union North General Service - 2014 Proposed Delivery
Customer, Demand and Commodity-related Costs by Rate Class

Line No.	Particulars ($000's)	Rate 01 (a)	Rate 10 (b)	Total (c) = (a+b)
1	Customer Related Costs (1)	111,039	10,527	121,566
2	Demand Related Costs (2)	35,211	27,330	62,542
3	Commodity Related Costs (3)	-	-	-
4	Total Allocated Costs (line 1 + line 2 + line 3)	146,250	37,857	184,108

Notes:
(1) J.H-1-15-2, Attachment 4, line 1.
(2) J.H-1-15-2, Attachment 4, line 6.
(3) Union North commodity-related costs are associated with Dawn storage and Dawn-Trafalgar transmission. These costs are considered to be storage-related costs, not delivery-related.

Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **11**

DATE: **July 27, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

mind - and I think it was touched on by Mr. Shepherd, but I wanted to see if I could get a more detailed answer from you - is why you wouldn't run a full cost allocation, which presumably is what the weightings are a proxy for?

MR. PANKRAC: Based on the forecast data, you don't have all of the detailed material that you would need to feed a detailed cost study.

For example, for each of those subcategories you would have to come up with an appropriate design day. You would have to take it back to your engineering people, and break up that forecast and do things.

And so what you have is you already have means of proxying that, that take you very close to what your final numbers will be.

And so similar to what we did in 2007, we are taking that same approach.

MR. BUONAGURO: Now -- but I would assume that eventually, though, you want to do a proper cost allocation; correct?

MR. PANKRAC: Absolutely.

MR. BUONAGURO: And I guess if I make a -- by comparison, in the previous case, the EB-2005-0520 case, the proposed split in that case was implemented for the first time in the 2008 rate year; is that correct?

MR. PANKRAC: That's right. Our proposal was to implement it in the year following, as we are proposing now.

MR. BUONAGURO: And also with reference to that

UNION GAS LIMITED

Undertaking of Mr. Pankrac
To Mr. Shepherd

Please provide Exhibit H, Tab 1, Tables 11 and 12, with an additional two columns for 2012 Actual at the existing breakpoint.

Please see Attachment 1 for Table 11 and Attachment 2 for Table 12.

Union North
Annual General Service Delivery Bill Impacts of
2014 Rate Proposals

Line	Annual Volume	2012 Approved (1) - Annual Volume Breakpoint of 50,000 m^3		2013 Proposed - Annual Volume Breakpoint of 50,000 m^3		2014 Proposed - Annual Volume Breakpoint of 5,000 m^3		Annual Bill Impacts	
		Rate 01	Rate 10	Rate 01	Rate 10	Rate 01	Rate 10		
No.	(m^3/year)	($)	($)	($)	($)	($)	($)	($)	(%)
1	1,800	383.49		422.31		421.12		(1.19)	-0.3%
2	2,200	411.33		458.73		457.04		(1.69)	-0.4%
3	2,600	438.84		494.80		492.79		(2.01)	-0.4%
4	3,000	466.13		530.67		528.39		(2.28)	-0.4%
5	5,000	598.23		705.54		705.23		(0.31)	0.0%
6	7,000	726.61		876.55			889.80	13.25	1.5%
7	10,000	914.59		1,128.39			1,090.00	(38.39)	-3.4%
8	20,000	1,531.22		1,957.51			1,755.24	(202.27)	-10.3%
9	30,000	2,142.17		2,780.82			2,419.31	(361.50)	-13.0%
10	50,000	3,359.60		4,422.82			3,743.64	(679.18)	-15.4%
11	80,000		4,805.71		5,899.52		5,626.55	(272.97)	-4.6%
12	100,000		5,683.78		7,037.89		6,863.64	(174.24)	-2.5%
13	200,000		9,932.35		12,571.60		12,626.80	55.19	0.4%
14	300,000		13,864.38		17,752.05		17,917.17	165.12	0.9%
15	500,000		21,371.97		27,715.09		28,150.63	435.54	1.6%

Notes:
(1) Calculated using January 2012 QRAM rates as approved by the Board in EB-2011-0382. Includes monthly customer charge and delivery commodity portions only.

Union South
Annual General Service Delivery Bill Impacts of
2014 Rate Proposals

Line	Annual	2012 Approved (1) - Annual Volume Breakpoint of 50,000 m^3		2013 Proposed - Annual Volume Breakpoint of 50,000 m^3		2014 Proposed - Annual Volume Breakpoint of 5,000 m^3		Annual Bill Impacts	
	Volume	Rate M1	Rate M2	Rate M1	Rate M2	Rate M1	Rate M2		
No.	(m^3/year)	($)	($)	($)	($)	($)	($)	($)	(%)
1	1,800	313.37		323.12		324.97		1.85	0.6%
2	2,200	325.75		337.57		339.58		2.01	0.6%
3	2,600	338.01		351.94		354.09		2.14	0.6%
4	3,000	350.20		366.20		368.47		2.27	0.6%
5	5,000	410.12		436.44		439.21		2.77	0.6%
6	7,000	468.81		505.38			651.36	145.98	28.9%
7	10,000	556.60		608.53			749.11	140.58	23.1%
8	20,000	845.99		948.89			1,073.28	124.39	13.1%
9	30,000	1,134.90		1,288.78			1,396.41	107.64	8.4%
10	50,000	1,712.75		1,968.54			2,038.38	69.85	3.5%
11	80,000		3,730.75		4,031.07		2,987.00	(1,044.07)	-25.9%
12	100,000		4,428.16		4,804.38		3,616.58	(1,187.80)	-24.7%
13	200,000		7,761.05		8,521.82		6,720.25	(1,801.58)	-21.1%
14	300,000		10,999.89		12,148.30		9,797.39	(2,350.91)	-19.4%
15	500,000		17,381.76		19,308.57		15,922.58	(3,385.98)	-17.5%

Notes:
(1) Calculated using January 2012 QRAM rates as approved by the Board in EB-2011-0382. Includes monthly customer charge and delivery commodity portions only.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit H1, Tab 1, page 29, Updated

a) Please provide a breakdown of the 121 M4 customers forecast for 2013 by industry grouping.

b) Please provide a breakdown by industry grouping of the 595 customers currently taking service under Rate M2 that would qualify for the M4 rate.

c) Please provide a bill impact table, similar to Table 12 that shows the annual cost for the following customer profiles under Rate M2 in 2013 and under Rate M4 in 2014:

i) FCD = 2,400 m^3 & annual volume of 350,000 m^3;
ii) FCD = 2,400 m^3 & annual volume of 500,000 m^3;
iii) FCD = 3,600 m^3 & annual volume of 525,600 m^3;
iv) FCD = 3,600 m^3 & annual volume of 650,000 m^3.

Response:

a)

2013 Forecast Customer Count for M4	Count
Greenhouse	11
LCI/Key/Affiliated Steel	104
Total	115

(121 is the average number customers throughout the year while, 115 customers remained at year end)

b) The table below groups the 595 Rate M2 customers with annual volumes exceeding 350,000 m^3 that would potentially qualify for Rate M4 into market sector groupings.

Market Sector Groupings

Line No.	Market Sector	Number of Customers	Percentage of Customers
1	Commercial	302	50.6%
2	Manufacturing	193	32.5%
3	Institutional	70	11.8%
4	Chemical/Refinery	27	4.6%
5	Power	3	0.5%
6	Totals	595	100%

c) Please see Attachment 1.

Annual Delivery Bill Impacts - Union South
Customers in Rate M2 in 2013 moving to Rate M4 in 2014

Line No.	Firm Contract Demand (m^3/day)	Annual Volume (m^3)	Load Factor	2013 Proposed ($) Rate M2 (1)	2013 Proposed ($) Rate M4	2014 Proposed ($) Rate M2	2014 Proposed ($) Rate M4 (2)	Bill Impacts $	Bill Impacts %
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (g-d)	(i) = (h/d)
1	2,400	350,000	40.0%	17,246.01			18,362.00	1,115.99	6.5%
2	2,400	500,000	57.1%	24,015.08			20,017.14	(3,997.95)	-16.6%
3	3,600	525,600	40.0%	25,169.04			27,549.62	2,380.57	9.5%
4	3,600	650,000	49.5%	30,776.56			28,922.28	(1,854.29)	-6.0%

Notes:

(1) Includes impact of the 2013 proposed Rate M2 storage rate of 0.8338 cents/m^3.

(2) Based on parameters provided, all contract demand in first block demand and all throughput volume in first block commodity.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh H1/Tab 1 / pp.52-54

Union has proposed to modify the fuel ratio design for the Dawn to Dawn-Vector transportation service to recover UFG on all transportation activity in both the summer and winter periods. Please provide Union's rationale for this proposed modification.

Response:

Union's current fuel ratio design for the Dawn to Dawn-Vector firm transportation service only recovers UFG on 60 days of activity during the summer period. UFG should be recovered on all transportation activity in both summer and winter periods. Union's proposal to modify the fuel ratio design will recover UFG on all transportation activity and is consistent with how Union recovers UFG for other C1 firm transportation services.

A fuel ratio design that recovers UFG on all transportation activity was most recently approved in EB-2010-0207 for the C1 Dawn to Dawn–TCPL firm transportation service.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit H1, Tab 1, page 55, Updated

a) When was the current additional service charge of $15 approved by the Board?

b) What was the monthly charge for the M2 rate class when the current additional service charge of $15 was approved by the Board?

c) What was the basis of the charge of $15? Was it cost based?

d) Please explain why Union proposes to increase the additional service charge to $70 in 2013 and then reduced it to $35 in 2014 for the M2 class? Why not remove the volatility and increase it to $35 in 2013?

e) Please provide the number of accounts that are billed the $15 additional service charge for the last year of actual data available for each of the M1 and M2 rate classes.

f) What is the impact on the revenue forecast for each of the M1 and M2 rate classes based on Union's proposals for 2013? How has this additional revenue been included in the forecast?

g) If two or more M1 accounts qualify to combine their meter readings for billing purposes and the annual volume exceeds 5,000 m^3 in 2014, will they qualify to become an M2 customer? If not, please explain why not?

h) If the response to (g) is no, please confirm that the customer can combine his accounts by having Union provide one meter and providing their own behind the meter piping to serve multiple contiguous pieces of property of the same owner not divided by a public right-of-way. If this cannot be confirmed, please explain why.

i) If two or more M2 accounts qualify to combine their meter readings for billing purposes and the annual volume exceeds 350,000 m^3 in 2014 (and meet the firm CD requirements), will they qualify to become an M4 customer? If not, please explain why not?

j) If the response to (i) is no, please confirm that the customer can combine their accounts by having Union provide one meter and providing their own behind the meter piping to serve multiple contiguous pieces of property of the same owner not divided by a public right-of-way. If this cannot be confirmed, please explain why.

k) Can a customer with multiple M1 and M2 accounts located on contiguous pieces of property of the same owner that are not divided by a public right-of-way combine their accounts for billing purposes into an M2 account? If no, please explain why not.

l) Can a customer with multiple M1, M2 and/or M4 accounts located on contiguous pieces of property of the same owner that are not divided by a public right-of-way combine their accounts into an M4 account assuming the total volumes and firm CD qualify as an M4 customer? If no, please explain why not.

m) In either of the situations described in (k) and (l) above, please confirm that the customer can combine their accounts by having Union provide one meter and providing their own behind the meter piping to serve multiple contiguous pieces of property of the same owner not divided by a public right-of-way. If this cannot be confirmed, please explain why.

n) Does Union actively notify customers that may qualify to combine accounts and take advantage of the supplemental service to commercial and industrial customers under grouped meters? If not, why not?

o) Please confirm that the supplemental service to customers under grouped meters is not available to residential customers in either Rates M1 or M2. If confirmed, please provide Union's description of residential customers as compared to commercial customers.

p) What is the impact on existing customers that are taking advantage of the supplemental service to commercial and industrial customers under grouped meters of the change in the breakpoint between M1 and M2 from 50,000 m^3 to 5,000 m^3? In particular, will any customers that currently take advantage of this service be worse off as a result of the proposed change?

q) Does Union offer a similar supplemental service under Rates 01 and 10? If not, why not?

Response:

a) The current additional service charge of $15 per month was approved by the Board in the EBRO 388 Reasons for Decision, dated April 22, 1983.

b) The monthly charge for the Rate M2 rate class was $6.25 when the current additional charge of $15.00 was approved.

c) The additional service charge is not cost-based.

The basis of the $15 charge was an assessment of the net benefits to group billing customers measured by the difference between customer's bill with and without group billing.

In its EBRO 397 Decision with Reasons, the Board stated it *"is satisfied with the current arrangements with respect to group billing and will make no adjustments to the rate schedules with respect to this matter or to the $15.00 per month currently being levied in each additional meter."*

d) Union's proposal to match the additional service charge of $70 in 2013 and $35 in 2014 for the Rate M2 class to the monthly customer charge in proposed rates for each year is meant to ensure that Rate M2 customers who can combine meter readings do not receive an unintended benefit in comparison to Rate M2 customers who cannot combine meter readings.

If Union were to set the additional service charge to $35 in 2013, Rate M2 customers who combine meter readings would receive an unintended benefit in comparison to other Rate M2 customers who continue to pay a monthly customer charge of $70 for meter readings that cannot be combined. The intent of Union's proposal is to avoid this situation beginning in 2013.

e) For the last year of actual data ending April 4, 2012, 969 Rate M1 customers and 71 Rate M2 customers are billed the $15 additional service charge.

f) Based on the last year of actual data ending April 4, 2012, the additional revenue for 2013 would be:

i) Rate M1 = $69,768 (969 accounts x ($21-$15) x 12 months).
ii) Rate M2 = $46,860 (71 accounts x ($70-$15) x 12 months).

Should the Board approve Union's proposal to increase the additional service charges for Rate M1 and Rate M2, Union will update its 2013 proposed rates to recognize the additional forecast revenue.

g) No, two or more Rate M1 accounts that qualify to combine meter readings for billing purposes with annual volume that exceed 5,000 m^3 in 2014 will only qualify to become a Rate M2 customer if one account has an annual volume that exceeds 5,000 m^3. Union will not combine quantities of several Rate M1-size accounts such that eligibility to a different rate class results.

h) If the annual volume taken through a single meter exceeds 5,000 m^3, the customer is eligible for Rate M2 service. Service is only available provided Union determines it can serve the entire load through a single meter off a single distribution pipe.

i) No, two or more Rate M2 accounts who qualify to combine their meter readings for billing purposes and whose annual volume exceeds 350,000 m^3 in 2014 (and meet the firm CD requirements) will only qualify to become a Rate M4 customer if at least one account meets all the following criteria necessary to qualify for revised Rate M4 service in 2014:

a. an annual volume that exceeds 350,000 m^3;
b. a firm daily contracted demand of at least 2,400 m^3; and,
c. a load factor of at least 40% (i.e. 146 days use of contracted demand)

Union will not combine quantities of several Rate M2-size accounts such that eligibility to a different rate class results.

j) If a single meter meets all the eligibility criteria outlined in Union's response to (i) above, the customer is eligible for Rate M4 service. Service is only available provided Union determines it can serve the entire load through a single meter off a single distribution pipe.

k) Yes, provided that Union determines it can serve the entire load through a single meter off a single distribution pipe.

l) Yes, provided a single meter meets all the Rate M4 eligibility criteria and the total firm volumes and total firm CD qualify as a Rate M4 customer. Service is only available provided Union determines it can serve the entire load through a single meter off a single distribution pipe.

m) Yes, provided that Union determines it can serve the entire load through a single meter off a single distribution pipe.

n) Union does not actively notify customers that may qualify to combine accounts, however Consolidated Billing as well as Master Summary Billing is listed and described within the Conditions of Service, located electronically on the Union Gas website and in hardcopy at the Corporate Head Office and by mail.

Upon request of the customer, Union will complete a field investigation to determine if the customer's meters are located on contiguous tracts of land not divided by a public right-of-way as per the requirements for consolidated billing, and if eligible, the customer's meters are consolidated for billing purposes.

o) Confirmed. Supplemental service to customers under grouped meters is not available to residential customers in either Rate M1 or Rate M2.

Descriptions of the residential and commercial customers, provided at Exhibit A1, Tab 13, Schedule 1, Updated, Attachment, page 3, under the heading "Service" are as follows:

<u>Residential</u>: Customers supplied for residential purposes in a single family dwelling or building, or in an individual flat or apartment within a multiple family dwelling or building or a portion of a building occupied as the home, residence, or sleeping place of one or more

persons.

When service for residential purposes is supplied to two or more families served as a single customer under one rate classification contract that service is considered as commercial but is counted as only one customer.

Residential premises also used regularly for professional or business purposes (such as doctor's office in a home or where a small store is integral with the living space), are considered as residential where the residential use of gas is half or more than half of the total service.

Commercial: Applies to customers engaged in selling, warehousing or distributing a commodity, in some business activity or in some other form of economic or social activity (also includes professions).

The size of the customer's operation or volume of use is not a criterion for determining Commercial service.

p) The reduction in the annual volume breakpoint between Rate M1 and Rate M2 from 50,000 m^3 to 5,000 m^3 impacts current commercial and industrial customers under grouped meters is as follows:

Rate M1:

No impact on monthly charges since Union proposes no further changes in the monthly charge or supplemental meter charge for 2014.

Delivery charges for 2013 and 2014 are similar.

Rate M2:

The proposed 2014 reduction in the monthly charge from $70 per month to $35 per month and consequently the additional charge for supplemental meters, reduces the monthly charges to these accounts. Please refer to Union's response in part (d) above.

The lower annual volume requirement for Rate M2 means more supplemental meters with annual volumes may qualify for Rate M2 service provided at least one account meets the Rate M2 eligibility criteria. Please refer to Union's response in part (g) above.

The reduction in delivery charges is favourable to eligible commercial and industrial customers under group meters.

Customers who continue service in Rate M1 will see minimal impact. Customers who continue service in Rate M2 will be no worse off.

With the annual volume breakpoint reduction in 2014 some customers currently served under Rate M1 will be taking Rate M2 service. The increase in the monthly charge and additional meter charge increase from $21 in Rate M1 to $35 in Rate M2 will be partially or fully offset by reduced M2 delivery rates. Individual customer impacts will vary.

q) Yes, however Rate 01 and Rate 10 accounts do not have an additional service charge for each additional meter.

Table 21

Proposed C1 Firm Dawn to Dawn-Vector Transportation Fuel Ratio - April 1st to October 31st
Effective January 1, 2013

Line No.	Particulars	Units	Fuel (a)	UFG (b)	Total (c)
1	Total Fuel and UFG	GJ	22,525	19,673	42,198
2	Forecasted Activity 60 days	GJ	4,904,944	N/A	N/A
3	Fuel Ratio Over 60 days	%	0.459%	N/A	N/A
4	Forecasted Activity 214 days	GJ	12,709,732	12,709,732	12,709,732

For the November 1 to March 31 winter period, Union is proposing to recover UFG from Dawn to Dawn-Vector customers on all forecasted transportation activity. There is no compressor fuel forecasted for the Dawn to Dawn-Vector firm transportation service in the winter months. The proposed winter fuel ratio for the C1 Dawn to Dawn-Vector transportation service is 0.155% and will recover UFG only.

7/ OTHER RATE SCHEDULE CHANGES

a) IN-FRANCHISE RATE SCHEDULES

Union is proposing to update the additional service charge applicable to "Supplemental Service to Commercial and Industrial Customers under Group Meters" in Rate M1 and Rate M2. The supplemental service allows for the combination of readings from several meters, where the meters are located on contiguous pieces of property of the same owner and are not divided by a public right-of-way.

Union proposes to increase the additional service charge on the Rate M1 rate schedule from the current approved $15 per month to $21 per month. On the Rate M2 rate schedule, Union proposes to increase the additional service charge from the current approved $15 per month to $70 per month ($35 per month in 2014). Union is proposing to increase the additional service charge to ensure that customers who combine readings from several meters do not receive an unintended benefit in comparison to customers who cannot combine meter readings. This change will result in all Rate M1 and Rate M2 customers paying the same monthly customer charge for all meter readings.

The increase in the additional service charge on the Rate M1 and Rate M2 rate schedules will align this charge with the proposed monthly customer charges in each rate class going forward.

b) EX-FRANCHISE RATE SCHEDULES

Union is proposing several ex-franchise rate schedule changes that are intended to provide greater clarity and consistency. The proposed ex-franchise rate schedule changes are discussed below.

a) Based on a monthly customer charge for Rate M2 of $25 or $30 and the resulting increases in the variable rate requested in the previous technical conference question, please provide a version of Attachment 1 to Exhibit J.H-5-2-1 for each of the monthly customer charges.
b) Based on Union's proposal as shown in Attachment 1, what is the annual volume needed to make the costs under Rates M2 and M4 equivalent for a firm contract demand of 2,400 m3? for a firm contract demand of 3,600 m^3?

4. Ref: Ex. J.H-5-11-1

Please confirm that the 140 days use of firm contract demand noted on the first line of page 2 should be 146 days of firm contract demand.

5. Ref: Ex. J.H-10-2-1

The response indicates, that for billing purposes a number of M1 accounts cannot be grouped to become an M2 account and that a number of M2 accounts cannot be grouped to become an M4 account. The responses to part (k) and (l) appear to indicate that a customer with M1 and M2 accounts can aggregate them into an M2 account and a customer with M1 or M2 and an M4 account can aggregate them into an M4 contract.

a) Is the above correct?
b) Is a single meter required to aggregate these accounts for billing purposes?

6. Ref: Ex. J.H-10-2-1

With respect to part (q) of the response, Union indicates that it does offer a similar supplemental service under rates 01 and 10 but that there is no additional service charge for each additional meter.

a) Does the supplemental service available to rates 01 and 10 allow the volumes of the accounts combined to take advantage of the lower rates for higher volume blocks as does the M1 and M2 supplemental service?
b) Why is Union charging a service charge for each additional meter in Rates M1 and M2 but not for Rates 01 and 10?

1.

a) In J.H-1-1-2 part c) Union stated that the revenue requirement impact associated with the increase in equity component of its capital structure from 36% to 40% was approximately $15 million.

   As per Exhibit E1, Tab 1, Updated, Page 2, Footnote 1, the actual revenue requirement impact associated with the increase in equity component of Union’s capital structure from 36% to 40% is $17.3 million.

Union has assumed an increase in the equity component of its capital structure from 36% to 37% in 2013. The revenue requirement impact associated with a 1% increase in equity thickness is approximately $4.3 million.

Based on a revenue requirement impact of $4.3 million versus $17.3 million, Union North delivery rates would increase by an average of 18.3% and Union South delivery rates would increase by an average of 5.6%.

b) As described in J.H-1-1-2 part c) Union's proposal to change its weather normalization method from the current 55:45 method to 100% 20-year declining trend increases its revenue deficiency by approximately $7 million.

   Union has assumed that the change in the weather normalization method is implemented over five years. The revenue deficiency impact associated with a five year phase-in is approximately $1.4 million in 2013.

   Based on a revenue deficiency impact of $1.4 million versus $7 million, Union North delivery rates would increase by an average of 18.6% and Union South delivery rates would increase by an average of 6.2%.

c) Based on the revenue requirement and revenue deficiency impacts described in parts a) and b) above combined, Union North delivery rates would increase by an average of 16.8% and Union South delivery rates would increase by an average of 4.9%.

d) No, the projected loss of the FT-RAM does not affect Union North delivery rates only.

e) As described in J.H-1-1-2 part c), Union has considered a partial rate mitigation measure whereby FT-RAM revenue is included in Union North delivery rates. Union would require deferral account protection to manage the possibility that the FT-RAM program is eliminated or changed materially in TCPL's NEB rate proceeding.

f) Union has derived revenue to cost ratios based on achieving a $31 bill increase for both Rate 01 and Rate M1 general service customers only. To achieve a $31 bill increase approximately $13 million in revenue was shifted from Rate 01 to Rate M1.

   Based on the assumptions above, the revenue to cost ratio in Rate 01 decreases from 0.984 to 0.904. The revenue to cost ratio in Rate M1 increases from 1.001 to 1.033.

2.

a) Union arrived at the proposed 2014 monthly customer charge of $35 for Rate 10 and Rate M2 by taking the approximate mid-point of the monthly customer charges required to recover all customer-related costs.

Table 1

Setting the 2014 Monthly Customer Charge
for Rate 10 and Rate M2

Line No.	Particulars ($000's)	Rate 10 (a)	Rate M2 (b)
1	Customer-Related Costs	10,527	22,006
2	Annual Billing Units	254,880	730,658
3	Monthly Customer Charge	$ 41.30	$ 30.12

b) Please see Attachment 1 showing the bill impacts and corresponding rates if the monthly customer charge for Rate 10 and Rate M2 is set at $25 per month.

Please see Attachment 2 showing the bill impacts and corresponding rates if the monthly customer charge for Rate 10 and Rate M2 is set at $30 per month.

c) No, Union has set the monthly customer charge for Rate 10 and Rate M2 customers to recover a reasonable proportion of the fixed costs allocated to these rate classes.

3.

a) Please see Attachment 3 showing the Rate M2 and Rate M4 comparison with a 2014 Rate M2 monthly customer charge set at $25.

Please see Attachment 4 showing the Rate M2 and Rate M4 comparison with a 2014 Rate M2 monthly customer charge set at $30.

b) For a firm contract demand of 2,400 m^3, the annual volume that makes the Rate M2 and Rate M4 costs equivalent is 382,593 m^3 (or a load factor of about 43.7%).

For a firm contract demand of 3,600 m^3, the annual volume that makes the Rate M2 and Rate M4 costs equivalent is 595,505 m^3 (or a load factor of about 45.3%).

4. Confirmed.

5.

a) Yes.

b) No.

6.

a) Yes.

b) The practice of combining meter readings from several meters for eligible Rate 01 and Rate 10 customers without charging the additional service charge has not been harmonized between Union North and Union South.

UNION GAS LIMITED

Undertaking of Mr. Tetreault
To Mr. Wolnik

Please explain what other measures, by order of priority, could be used to reach 10 percent threshold, if the four mitigation tools were insufficient.

The Board's guidance to electricity distributors regarding rate mitigation contemplates a mitigation plan where a customer class or group **total** bill increase exceeds 10%. There is no comparable guidance provided to gas distributors. Union's proposed deficiency and the associated total bill impacts for each rate class fall below the 10% threshold. Please see Attachment 1.

Union does not consider mitigation to be necessary. If mitigation were ordered by the Board, any one of the mitigation measures included in Exhibit J.H-1-1-2 would keep the total bill impact below 10%.

Notwithstanding the fact that the total bill impacts provided in Attachment 1 do not exceed 10% for any in-franchise rate class, Union has provided Attachment 2. Attachment 2 provides the delivery rate impact associated with the expected reduction in return on equity ("ROE") from 9.58% to 9.10%, the impact of an alternative allocation of the distribution-related rate base reduction agreed to at Issue 1.4 of the EB-2011-0210, Settlement Agreement ("Settlement") and the mitigation measures discussed at Exhibit J.H-1-1-2.

ROE Reduction 9.58% to 9.10%
Based on the June 2012 Consensus of 2012 actual and forecast bond yields, the Board's formula produces an ROE of 9.10%. The ROE included in the revenue requirement underpinning delivery rate impacts provided at Exhibit H1, Tab 1, Schedule 1, revised for the Settlement is 9.58%. Before considering the impact of mitigation measures on delivery rates it is appropriate to adjust for the reduced ROE. The revenue requirement impact of going from 9.58% to 9.10% is approximately $8.6 million.

FT-RAM Revenue
At Exhibit J.C-4-7-9, Union indicated that if TCPL's RAM program is not eliminated on November 1, 2012, Union's 2013 revenue forecast attributable to FT-RAM would be $11.6 million. In preparing Attachment 2, Union has reduced delivery rates by $11.6 million to reflect the continuation of TCPL's RAM program beyond November 1, 2012.

Should the Board order the inclusion of FT-RAM revenue in delivery rates, Union would require deferral account protection, including the attributes as described at Transcript Volume 7 pp. 35-37, against the risk of elimination of the RAM program.

Alternative Allocation of Distribution-Related Rate Base Adjustment

At Issue 1.4 of the Settlement, parties agreed to reduce distribution-related rate base by $12 million. The effect of the reduction was a revenue requirement reduction of approximately $1.7 million.

To implement the distribution-related rate base reduction, Union reduced distribution mains, the largest distribution-related plant type. In cross-examination, parties requested that Union consider an alternative method for incorporating the distribution-related rate base adjustment and provide the impact of that alternative.

For the purposes of preparing Attachment 2, rather than attributing the rate base adjustment to distribution mains, Union allocated the adjustment using total distribution rate base. The impact of the alternative allocation is provided at column (h) of Attachment 2.

Phase In of Increase in Common Equity Ratio

For the purposes of preparing Attachment 2, Union was asked to assume that its proposal to increase its common equity ratio from 36% to 40% would be phased in over four years starting in 2013. Phasing in the increase in common equity thickness over four years reduces the 2013 revenue deficiency by approximately $11.1 million.

Phase In of the 20-Year Declining Trend Weather Methodology

As described in J.H-1-1-2 part c) Union's proposal to change its weather normalization method from the current 55:45 method to 100% 20-year declining trend increases its revenue deficiency by approximately $7 million. For the purposes of preparing Attachment 2, Union was asked to assume that the change in the weather normalization method would be implemented over five years starting in 2013. Phasing in the weather normalization method over five years reduces the 2013 revenue deficiency by approximately $5.8 million.

Adjustments to Revenue to Cost Ratios and Other Mitigation Methods

The mitigation measures above were sufficient to reduce the delivery rate impacts below 10%. Accordingly, there were no additional amounts to be deferred for future recovery and no need to adjust revenue to cost ratios. Union's view is that no further adjustments should be made to the revenue to cost ratios between North and South unless the Board was to set a longer term direction for Union to harmonize rate levels as well as rate structures between North and South customers.

Union North
Calculation of Annual Bill Impacts for Typical Small and Large Customers

Line No.	Particulars	Current Approved Bill ($) (a)	Current Approved Unit Rate (cents/m³) (b)	2013 Proposed Bill ($) (c)	2013 Proposed Unit Rate (cents/m³) (d)	Impact Unit Rate (cents/m³) (e) = (d-b)	Impact Bill ($) (f) = (c-a)	Impact Bill (%) (g) = (f/a)	Volumes Used for Rate Calcs
1	Small Rate 01								
2	Delivery Charges	404	18.3500	459	20.8509	2.5009	55	13.6%	2,200
3	Gas Supply Charges	469	21.3359	480	21.7968	0.4609	10	2.2%	2,200
	Total Bill	873	39.6859	938	42.6477	2.9618	65	7.5%	2,200
4	Small Rate 10								
5	Delivery Charges	4,224	7.0394	4,699	7.8320	0.7925	476	11.3%	60,000
6	Gas Supply Charges	12,188	20.3141	12,334	20.5563	0.2422	145	1.2%	60,000
	Total Bill	16,412	27.3535	17,033	28.3883	1.0348	621	3.8%	60,000
7	Large Rate 10								
8	Delivery Charges	13,228	5.2912	15,209	6.0837	0.7926	1,981	15.0%	250,000
9	Gas Supply Charges	50,785	20.3141	51,391	20.5564	0.2423	606	1.2%	250,000
	Total Bill	64,013	25.6053	66,600	26.6401	1.0348	2,587	4.0%	250,000
10	Small Rate 20								
11	Delivery Charges	54,251	1.8084	71,780	2.3927	0.5843	17,529	32.3%	3,000,000
12	Gas Supply Charges	605,494	20.1831	595,032	19.8344	(0.3488)	(10,463)	-1.7%	3,000,000
	Total Bill	659,745	21.9915	666,811	22.2270	0.2355	7,066	1.1%	3,000,000
13	Large Rate 20								
14	Delivery Charges	204,868	1.3658	271,339	1.8089	0.4431	66,471	32.4%	15,000,000
15	Gas Supply Charges	2,865,317	19.1021	2,818,008	18.7867	(0.3154)	(47,308)	-1.7%	15,000,000
	Total Bill	3,070,185	20.4679	3,089,348	20.5957	0.1278	19,163	0.6%	15,000,000
	Average Rate 25								
16	Delivery Charges	33,278	1.7988	42,569	2.3010	0.5022	9,291	27.9%	1,850,000
17	Gas Supply Charges	326,112	17.6277	344,766	18.6360	1.0083	18,654	5.7%	1,850,000
18	Total Bill	359,391	19.4265	387,335	20.9370	1.5105	27,945	7.8%	1,850,000
	Small Rate 100								
19	Delivery Charges	207,338	0.7679	272,804	1.0104	0.2425	65,466	31.6%	27,000,000
20	Gas Supply Charges	5,508,162	20.4006	5,481,147	20.3005	(0.1001)	(27,015)	-0.5%	27,000,000
21	Total Bill	5,715,500	21.1685	5,753,951	21.3109	0.1424	38,451	0.7%	27,000,000
	Large Rate 100								
22	Delivery Charges	1,713,524	0.7140	2,208,728	0.9203	0.2063	495,204	28.9%	240,000,000
23	Gas Supply Charges	48,118,849	20.0495	47,877,126	19.9488	(0.1007)	(241,724)	-0.5%	240,000,000
24	Total Bill	49,832,373	20.7635	50,085,853	20.8691	0.1056	253,480	0.5%	240,000,000

Union South
Calculation of Annual Bill Impacts for Typical Small and Large Customers

	Small Rate M1								
25	Delivery Charges	340	15.4464	355	16.1350	0.6886	15	4.5%	2,200
26	Gas Supply Charges	392	17.8227	390	17.7073	(0.1155)	(3)	-0.6%	2,200
27	Total Bill	732	33.2691	745	33.8423	0.5732	13	1.7%	2,200
	Small Rate M2								
28	Delivery Charges	3,387	5.6453	3,738	6.2306	0.5853	351	10.4%	60,000
29	Gas Supply Charges	10,694	17.8227	10,624	17.7070	(0.1157)	(69)	-0.6%	60,000
30	Total Bill	14,081	23.4680	14,363	23.9376	0.4696	282	2.0%	60,000
	Large Rate M2								
31	Delivery Charges	10,906	4.3623	12,369	4.9476	0.5853	1,463	13.4%	250,000
32	Gas Supply Charges	44,557	17.8227	44,268	17.7070	(0.1157)	(289)	-0.6%	250,000
33	Total Bill	55,463	22.1850	56,637	22.6547	0.4696	1,174	2.1%	250,000
	Small Rate M4								
34	Delivery Charges	33,628	3.8432	38,172	4.3626	0.5193	4,544	13.5%	875,000
35	Gas Supply Charges	155,949	17.8227	154,936	17.7070	(0.1157)	(1,012)	-0.6%	875,000
36	Total Bill	189,577	21.6659	193,109	22.0696	0.4036	3,532	1.9%	875,000
	Large Rate M4								
37	Delivery Charges	237,903	1.9825	291,342	2.4278	0.4453	53,439	22.5%	12,000,000
38	Gas Supply Charges	2,138,724	17.8227	2,124,840	17.7070	(0.1157)	(13,884)	-0.6%	12,000,000
39	Total Bill	2,376,627	19.8052	2,416,182	20.1348	0.3296	39,555	1.7%	12,000,000
	Small Rate M5								
40	Delivery Charges	20,602	2.4972	27,525	3.3363	0.8392	6,923	33.6%	825,000
41	Gas Supply Charges	147,037	17.8227	146,083	17.7070	(0.1157)	(955)	-0.6%	825,000
42	Total Bill	167,639	20.3199	173,608	21.0433	0.7235	5,969	3.6%	825,000
	Large Rate M5								
43	Delivery Charges	102,925	1.5835	141,680	2.1797	0.5962	38,754	37.7%	6,500,000
44	Gas Supply Charges	1,158,476	17.8227	1,150,955	17.7070	(0.1157)	(7,521)	-0.6%	6,500,000
45	Total Bill	1,261,401	19.4062	1,292,635	19.8867	0.4805	31,234	2.5%	6,500,000
	Small Rate M7								
46	Delivery Charges	579,244	1.6090	611,959	1.6999	0.0909	32,715	5.6%	36,000,000
47	Gas Supply Charges	6,416,172	17.8227	6,374,520	17.7070	(0.1157)	(41,652)	-0.6%	36,000,000
48	Total Bill	6,995,416	19.4317	6,986,479	19.4069	(0.0248)	(8,937)	-0.1%	36,000,000
	Large Rate M7								
49	Delivery Charges	2,298,408	4.4200	2,337,963	4.4961	0.0761	39,556	1.7%	52,000,000
50	Gas Supply Charges	9,267,804	17.8227	9,207,640	17.7070	(0.1157)	(60,164)	-0.6%	52,000,000
51	Total Bill	11,566,212	22.2427	11,545,603	22.2031	(0.0396)	(20,608)	-0.2%	52,000,000
	Small Rate M9								
52	Delivery Charges	130,944	1.8841	124,832	1.7962	(0.0879)	-6,112	-4.7%	6,950,000
53	Gas Supply Charges	1,238,678	17.8227	1,230,637	17.7070	(0.1157)	(8,041)	-0.6%	6,950,000
54	Total Bill	1,369,622	19.7068	1,355,469	19.5032	(0.2036)	(14,153)	-1.0%	6,950,000
	Large Rate M9								
55	Delivery Charges	388,775	1.9267	370,961	1.8384	(0.0883)	-17,815	-4.6%	20,178,000
56	Gas Supply Charges	3,596,264	17.8227	3,572,918	17.7070	(0.1157)	(23,346)	-0.6%	20,178,000
57	Total Bill	3,985,040	19.7494	3,943,879	19.5454	(0.2040)	(41,160)	-1.0%	20,178,000
	Small Rate T1								
58	Delivery Charges	94,362	1.2520	126,861	1.6832	0.4312	32,500	34.4%	7,537,000
59	Gas Supply Charges	1,343,297	17.8227	1,334,577	17.7070	(0.1157)	(8,720)	-0.6%	7,537,000
60	Total Bill	1,437,658	19.0747	1,461,438	19.3902	0.3155	23,780	1.7%	7,537,000
	Average Rate T1								
61	Delivery Charges	154,443	1.3353	196,360	1.6977	0.3624	41,917	27.1%	11,565,938
62	Gas Supply Charges	2,061,362	17.8227	2,047,981	17.7070	(0.1157)	(13,382)	-0.6%	11,565,938
63	Total Bill	2,215,805	19.1580	2,244,341	19.4047	0.2467	28,536	1.3%	11,565,938
	Large Rate T1								
64	Delivery Charges	373,237	1.4566	441,716	1.7238	0.2672	68,479	18.3%	25,624,080
65	Gas Supply Charges	4,566,903	17.8227	4,537,256	17.7070	(0.1157)	(29,647)	-0.6%	25,624,080
66	Total Bill	4,940,140	19.2793	4,978,971	19.4308	0.1515	38,831	0.8%	25,624,080
	Small Rate T2								
67	Delivery Charges	501,369	0.8461	510,436	0.8614	0.0153	9,067	1.8%	59,256,000
68	Gas Supply Charges	10,561,019	17.8227	10,492,460	17.7070	(0.1157)	(68,559)	-0.6%	59,256,000
69	Total Bill	11,062,389	18.6688	11,002,896	18.5684	(0.1004)	(59,492)	-0.5%	59,256,000
	Average Rate T2								
70	Delivery Charges	1,377,649	0.6965	1,172,515	0.5928	(0.1037)	-205,134	-14.9%	197,789,850
71	Gas Supply Charges	35,251,492	17.8227	35,022,649	17.7070	(0.1157)	(228,843)	-0.6%	197,789,850
72	Total Bill	36,629,140	18.5192	36,195,164	18.2998	(0.2194)	(433,976)	-1.2%	197,789,850
	Large Rate T2								
73	Delivery Charges	2,366,153	0.6393	1,907,986	0.5155	(0.1238)	-458,168	-19.4%	370,089,000
74	Gas Supply Charges	65,959,852	17.8227	65,531,659	17.7070	(0.1157)	(428,193)	-0.6%	370,089,000
75	Total Bill	68,326,006	18.4620	67,439,645	18.2225	(0.2395)	(886,361)	-1.3%	370,089,000
	Large Rate T3								
76	Delivery Charges	2,940,945	1.0784	3,111,819	1.1411	0.0627	170,873	5.8%	272,712,000
77	Gas Supply Charges	48,604,642	17.8227	48,289,114	17.7070	(0.1157)	(315,528)	-0.6%	272,712,000
78	Total Bill	51,545,587	18.9011	51,400,932	18.8481	(0.0530)	(144,654)	-0.3%	272,712,000

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit H1, Tab 3, Updated

a) Please provide a summary of the changes proposed to the gas supply administration fee.

b) What is the dollar impact by rate class of the changes proposed for the gas supply administration fee?

Response:

a) The calculation of the proposed 2013 gas supply administration fee is consistent with the methodology approved by the Board in EB-2005-0520. A comparison of the calculation between current Board-approved and 2013 proposed Gas Supply Administration fees is provided at Attachment 1.

b) Please see Attachment 2.

Gas Supply Administration Fee Calculation
Current Board-approved vs. 2013 Proposed

Line No.	Particulars ($000's)	Current Board-approved	2013 Proposed	Variance
		(a)	(b)	(c) = (b -a)
	Costs			
1	Return on Rate Base	614	174	(440)
2	Depreciation Expense	0	297	297
3	Accumulated Deferred Tax Drawdown	0	(6)	(6)
4	Taxes	106	30	(75)
5	General Operating & Engineering	1,147	1,264	117
6	Sales Promotion & Merchandise	0	176	176
7	Distribution Customer Accounting	6,157	2,238	(3,919)
8	Administration & General Expense	1,319	3,015	1,696
9	Total Costs	9,342	7,189	(2,153)
10	Sales Service Volumes (10^3m^3)	2,976,764	3,448,400	471,637
11	Gas Supply Administration Fee (cents/m^3) (line 9 / line 10)	0.3138	0.2085	(0.1053)

Impact by Rate Class of the 2013 Proposed Gas Supply Administration Fee

Line No.	Particulars	Current Approved Rate (cents/m^3)	2013 Forecast Sales Service Volume (10^3m^3)	Current Approved Revenue ($000's)	2013 Proposed Rate (cents/m^3)	2013 Forecast Sales Service Volume (10^3m^3)	2013 Proposed Revenue ($000's)	Revenue Deficiency/ (Sufficiency) ($000's)
		(a)	(b)	(c) = (a x b)	(d)	(e)	(f) = (d x e)	(g) = (f - c)
1	Rate 01	0.3138	621,731	1,951	0.2085	621,731	1,296	(655)
2	Rate 10	0.3138	150,962	474	0.2085	150,962	315	(159)
3	Rate 20	0.3138	13,514	42	0.2085	13,514	28	(14)
4	Rate 25	0.3138	42,913	135	0.2085	42,913	89	(45)
5	Rate M1	0.3138	2,221,004	6,970	0.2085	2,221,004	4,630	(2,340)
6	Rate M2	0.3138	367,242	1,153	0.2085	367,242	766	(387)
7	Rate M4	0.3138	16,855	53	0.2085	16,855	35	(18)
8	Rate M5	0.3138	14,132	44	0.2085	14,132	29	(15)
9	Rate M10	0.3138	48	0	0.2085	48	0	(0)
10	Total		3,448,400	10,822		3,448,400	7,189	(3,632)

Deferral Account Summary

Account Name	**Account Number**	**Proposed Changes (if any)**
Gas Cost Deferral Accounts		
TCPL Tolls and Fuel – Northern & Eastern Operations Area	179-100	Continue
North Purchase Gas Variance Account	179-105	Continue
South Purchase Gas Variance Account	179-106	Continue
Spot Gas Variance Account	179-107	Continue
Unabsorbed Demand Cost Variance Account	179-108	Continue
Inventory Revaluation Account	179-109	Continue as proposed
Storage and Transportation Deferral Accounts		
Short-term Storage and Other Balancing Services	179-70	Continue as proposed
Long-term Peak Storage	179-72	Continue
Other Deferral Accounts		
Lost Revenue Adjustment Mechanism	179-75	Continue
Unbundled Services Unauthorized Storage Overrun	179-103	Continue
Demand Side Management Variance Account	179-111	Continue
Gas Distribution Access Rule (“GDAR”) Costs	179-112	Continue
Late Payment Penalty Litigation	179-113	Close effective January 1, 2013
Shared Savings Mechanism	179-115	Continue
Carbon Dioxide Offset Credits	179-117	Continue
Average Use Per Customer	179-118	Continue as proposed
CGAAP to IFRS Conversion Cost	179-120	Continue
Cumulative Under-Recovery – St. Clair Transmission Line	179-121	Continue
Impact of Removing St. Clair Transmission Line from Rates	179-122	Continue
Conservation Demand Management	179-123	Continue
Harmonized Sales Tax	179-124	Close Effective January 1, 2013
Energy Technology and Innovation Canada (“ETIC”) Program	179-xxx	Open effective January 1, 2013

Union proposes to change the description of the Short-term Storage and Other Balancing Services deferral account in the accounting order to update the list of revenues included in the account and the proposed short-term storage margin sharing methodology. The proposed accounting order for the Short-term Storage and Other Balancing Services allows the proper transactions to be included in the account and has been provided in Appendix C.

Other Deferral Accounts

Average Use Per Customer (Deferral Account No. 179-118)

The Average Use per Customer deferral account was established in EB-2007-0606. Union proposes to continue tracking the average use per customer in the existing deferral account.

Union also proposes to change the description of AU deferral account in the accounting order to remove the limitation that makes it applicable only to the current incentive regulation plan, 2008 through 2012. The proposed accounting order for the AU deferral account will allow it to be in effect until it is changed or eliminated.

The proposed AU deferral accounting order has been provided at Appendix C.

3/ SPECIFIC DEFERRAL ACCOUNT PROPOSALS

Union proposes to create the following deferral account effective January 1, 2013:

Technology and Innovation Canada ("ETIC")

This account will track the difference between actual spending for ETIC and the amount approved for recovery in rates. Further details regarding ETIC can be found at Exhibit D1, Tab 10.

The proposed ETIC deferral accounting order has been provided at Appendix C.

4/ PROPOSED ACCOUNT CLOSURES

Union is proposing the closure of the following accounts effective January 1, 2013:

Late Payment Penalty Litigation (Deferral Account No.179-113)

The Late Payment Penalty Litigation deferral account was established in 2004 to record the costs incurred by the Company in connection with the late payment penalty litigation. This includes the Company's legal costs, costs of actuarial advice, costs of analyzing historic billing records and the cost of any judgment against the Company. The litigation in connection to late payment is now complete. Union proposes to close this account effective January 1, 2013.

Harmonized Sales Tax ("HST") (Deferral Account No. 179-124)

This account was established to record the amount of Provincial Sales Tax previously paid and collected in approved rates that is now subject to HST tax credits (i.e. the savings to Union). Also, it is used to record the amount of HST paid on taxable items for which no tax credits are received (i.e. the additional costs to Union). Union has shared the net impact 50/50 between the ratepayers and the shareholders. Union does not see a need to continue with this deferral account as Union's budget includes the impact of HST. Upon settlement of the balance in the account Union proposes to close this account effective January 1, 2013.

below, the O&M reduction of $9.550 million is agreed to for the purpose of arriving at an overall financial settlement. The revised budget is set out in Appendix B, Schedule 5 attached to this Agreement. For greater certainty, acceptance of the revised O&M budget by the parties does not impose any restrictions on Union with respect to its discretion to manage its overall 2013 O&M budget once approved by the Board.

Energy Technology Innovation Canada ("ETIC")

At D1/T10, Union proposed to include in its 2013 O&M budget $5.0 million related to ETIC. The parties agree that the $5.0 million ETIC budget will be removed from Union's 2013 O&M budget.

Community Investment

At D1/T8, Union proposed to include in its 2013 O&M budget $0.374 million of community investment spending. The parties accept Union's revised proposal to remove the $0.374 million community investment budget from Union's 2013 O&M budget.

Firm All Day Transportation Service ("F24T")

The parties accept two adjustments related to the F24T service. First, Union agrees to reduce the provision in the O&M budget for salaries and wages related to the F24T service by $0.250 million. Second, Union agrees to recognize that the remaining resources also support non-utility functions and therefore to attribute a further $0.250 million of F24T costs to Union's non-utility storage operations.

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Aiken

Please add to Attachment 1 the same type of information that would have been in accounts 179-73 and 179-74 for the 2010 through 2013 period.

Please see the Attachment.

Union Gas Limited
Summary of Transmission-Related Transactional Services
For the Years Ending December 31
($000's)

Line No.	Particulars		Actual 2010 (a)	Actual 2011 (b)	Forecast 2012 (c)	Forecast 2013 (d)
	Transportation and Exchange Services Previously Account #179-69					
1	Net Revenue	(1)	33,100	44,245	32,186	20,186
2	Less: Costs		12,557	9,965	9,040	6,448
3	Gross Margin		20,543	34,280	23,146	13,738
4	Less: Board Approved Margin in Rates		6,883	6,883	6,883	13,738
5	Hypothetical Deferred Margin	(2)	13,660	27,397	16,263	-
	Other S&T Services Previously Account #179-73					
6	Revenue		1,072	1,092	1,067	1,067
7	Less: Costs		75	76	75	75
8	Gross Margin		997	1,016	992	992
9	Less: Board Approved Margin in Rates		853	853	853	992
10	Hypothetical Deferred Margin	(2)	144	163	139	-
	Other Direct Purchase Services Deferral Account Previously Account #179-74					
11	Revenue		1,928	1,063	2,000	2,000
12	Less: Costs		1,311	782	1,360	1,360
13	Gross Margin	(3)	617	281	640	640
14	Less: Board Approved Margin in Rates		2,000	2,000	2,000	640
15	Hypothetical Deferred Margin	(2)	(1,383)	(1,719)	(1,360)	-

Notes:
(1) Revenue less direct costs to provide exchange services.
(2) Margin would have been subject to earnings sharing.
(3) Reduction in Other Direct Purchase Services due to return to system.

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME: **6**

DATE: **July 19, 2012**

BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

attention to this back in Mr. Thompson's compendium, and I apologize for bouncing around.

Can I ask you to turn to page 38 of Mr. Thompson's compendium?

And under item 14.1, we have an agreement, and what is it that Union had agreed to do with respect to S&T revenues in margin?

MR. ISHERWOOD: What Union had agreed to was to actually increase the S&T revenues -- in this case, actually, it is a margin number -- by 4.3 million.

So at that time, our margin forecast was 2.6 million, and by adding the 4.3, it took it to 6.9. And again, that's a margin -- margin, not revenue. And the 6.9 would have been then built into rates to provide rate relief for customers.

MR. SMITH: Can I ask you to turn back to the compendium -- my compendium again or our compendium again, at page 19.

You should have here Exhibit B2.2; do you have that, sir?

MR. ISHERWOOD: I do.

MR. SMITH: And there is a reference there to "DOS MN" and perhaps I should start by asking what "DOS MN" is.

MR. ISHERWOOD: DOSMN stands for Dawn overrun service must nominate; that is what the "DOS MN" stands for.

It was a service enhancement that TCPL added to FT contracts for the winter of 2008 and 2009.

They had previously sold some capacity from Dawn to escalations.

MR. AIKEN: Would it be fair to summarize that the protection going forward is the same as the protection you had in the past?

MS. ELLIOTT: Yes, absolutely.

MR. AIKEN: Okay, thank you. Panel, I have another compendium that I have filed and I put it on your desk at the break, the morning break. It is labelled "London Property Management Association Cross-Examination Compendium, Part 2."

Mr. Millar, if we could have an exhibit number for that, please?

MR. MILLAR: We can. Did you place copies of these at the desk here, Mr. Aiken?

MR. AIKEN: I did. It was on Mr. Viraney's chair.

MR. MILLAR: Oh... We have it now.

MS. HARE: The number, please, K6...

MR. MILLAR: Yes. K6.6.

EXHIBIT NO. K6.6: LONDON PROPERTY MANAGEMENT ASSOCIATION CROSS-EXAMINATION COMPENDIUM, PART 2.

MR. AIKEN: Ms. Elliott and others, do you have a copy of that?

MS. ELLIOTT: We do, yes.

MR. ISHERWOOD: We do.

MR. AIKEN: So if you could turn to the first page of K6.6, this is Exhibit J.DV-4-2-3.

This deals with the change in the wording for account number 179-70, the short-term storage and other balancing services.

The response to part a) seems to indicate that there are no sources of revenue that Union is currently aware of that may materialize in the future that would be based on the use of the utility storage space in excess of the in-franchise requirements that is not included in the proposed list of revenues. Have I got that correct?

MS. CAMERON: That's correct.

MR. AIKEN: Then this list of revenues is shown in the deferral account wording in Exhibit H1, tab 4, appendix C, which I have included at page 2 of the compendium, and I will read the relevant section. It says:

> "To record, as a debit (credit) in Deferral Account No. 179-70 the difference between actual net revenues for Short-Term Storage and Other Balancing Services including; Peak Short-Term Storage underpinned by excess utility storage assets, Off-Peak Short-Term Storage, Gas Loans and Supplemental Balancing Services and the net revenue forecast for these services as approved by the Board for ratemaking purposes."

Then in part b) of the interrogatory response, J.DV-4-2-3, I asked:

> "Does Union agree that any source of revenue that is received based on the use of the regulated utility storage space that is not included in the proposed list should be included in the deferral account?"

The response provided indicates that:

"Union expects to sell the space in excess of in-franchise requirements up to 100 PJ on a short-term basis."

Now, this response, while helpful, does not answer the question posed. Would Union agree to modify the wording in the deferral account to include, after the words "supplemental balancing services", the phrase, "and any other revenue generated through the use of excess utility storage assets"?

MS. ELLIOTT: As the deferral account is currently written, it's only the peak short-term storage in excess of the utility storage asset that applies to the utility storage assets.

Every other source of revenue going into this deferral account, we don't identify the assets that are associated with it. So 100 percent of those activities are currently going through this deferral account. There is no differentiation between utility assets and non-utility assets.

So the applicability for utility assets only relates to peak short-term storage.

MR. AIKEN: I guess my concern is we don't know what kind of services Union may develop over the next number of years that may be based on these excess utility storage assets.

So if there was a new service that was to be provided, say, two years from now, that was not defined as peak short-term storage underpinned by excess utility storage assets, would the revenues from that new service or new activity be included in this account, if they were underpinned by those assets?

MS. ELLIOTT: Yes.

MR. AIKEN: Okay.

Could you now turn to attachment 1 of Exhibit J.DV-2-2-1? This is on page 6 of the compendium.

This table shows the margins that would have been in account in 179-69 for the last three years had the account not been discontinued for the IRM period; have I got that correct?

MS. ELLIOTT: Yes, that's my understanding.

MR. AIKEN: Does the "Revenue" line at line 1 include FT RAM credits?

MS. ELLIOTT: It includes the exchange revenue earned as a result of utilizing FT RAM credits, yes, for optimization.

MR. AIKEN: Are there any costs associated with the FT RAM credits that would show up in line 2?

[Witness panel confers]

MS. ELLIOTT: If there were costs incurred to provide the service -- IT costs, for example -- they would be showing up in line 2, yes.

MR. AIKEN: Could you undertake to provide a version of this table that excludes the impact of FT RAM in the four years shown? Because my understanding, there is no FT RAM in 2013; is that correct?

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit C1, Tab 3, Updated & Exhibits C3, C4, C5 & C6, Tab 4, Schedule 1, as Updated.

a) Please provide a table that shows the revenue, costs and margins in the same format as the table shown as Attachment 1 to Exhibit C3/C16/C33.2 in EB-2007-0606 for each of the deferral accounts for transmission-related transactional services that were eliminated in EB-2007-0606 for the period 2010 through 2013, including actual data for 2011.

b) Please provide a reconciliation of the revenues used in the response to part (a) above with the revenues shown in Schedule 1 of Tab 4 in Exhibits C3 through C6, along with those discussed in Exhibit C1, Tab 3, Updated.

Response:

a) Please see Attachment 1. Union notes that had the transmission-related deferral accounts been in place over the IR term, the revenues and costs associated with these transactions would be excluded from the earnings sharing calculation.

b) Please see Attachment 2.

Summary of C1 Short-Term Transporation Service Block
For the Years Ending December 31
($000's)

Line No.	Particulars	Actual 2010 (a)	Actual 2011 (b)	Forecast 2012 (c)	Forecast 2013 (d)
	Total C1 Short-Term Transporation Service Block Previously Account #179-69				
1	Revenue	33,100	44,245	32,186	20,186
2	Less: Costs	12,557	9,965	9,040	6,448
3	Gross Margin	20,543	34,280	23,146	13,738
4	Less: Board Approved Margin in Rates	6,883	6,883	6,883	13,738
5	Hypothetical Deferred Margin	13,660	27,397	16,263	-

Reconciliation of C1 Short-Term Transporation Service Block Revenues
For the Years Ending December 31
($000's)

Line No.	Particulars		Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
			(a)	(b)	(c)	(d)
1	C1 Short-Term Transportation and Exchanges Revenue	(1)	32,554	44,228	32,186	20,186
2	M12 Transportation Overrun/Limited Firm	(2)	546	17	-	-
3	Total C1 Transportation Service Block Revenue		33,100	44,245	32,186	20,186

Note:
(1) As reported Exhibit C1, Summary Schedule 5, Line 4.
(2) Included as part of Exhibit C1, Summary Schedule 5, Line 1.

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Aiken

Please update chart at J.DV-2-2-1, Attachment 1, to exclude impact of FT RAM.

Please see the Attachment.

Union Gas Limited
Summary of Transportation and Exchange Services
For the Years Ending December 31

Line No.	Particulars ($000's)		Actual 2010 (a)	Actual 2011 (b)	Forecast 2012 (c)	Forecast 2013 (d)
	Transportation and Exchange Services Previously Account #179-69					
1	Net Revenue (Excluding FT-RAM Revenue)	(1)	21,400	22,245	17,986	20,186
2	Less: Costs (Excluding Costs Applicable to FT-RAM Revenue)		11,592	7,792	7,671	6,448
3	Gross Margin		9,808	14,453	10,315	13,738
4	Less: Board Approved Margin in Rates		6,883	6,883	6,883	13,738
5	Hypothetical Deferred Margin	(2)	2,925	7,570	3,432	-

Note:
(1) Revenue less direct costs to provide exchange services.
(2) Margin would have been subject to earnings sharing.

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Aiken

Please update table from JT1.13 to reflect year-to-date June actual and forecasts, and break out FT RAM credits included in line 4 as a separate line item.

Please see the Attachment.

UNION GAS LIMITED
Summary Revenue from Storage and Transportation of Gas

Line No.	Particulars ($000's)	Actual 2012 (June YTD) (a)	Forecast 2012 (June YTD) (b)	Difference (c)
	Transportation			
1	M12 Transportation	67,669	67,716	(47)
2	M12-X Transportation	2,208	2,215	(7)
3	C1 Long-term Transportation	3,643	3,391	252
4	C1 Short-term Transportation	6,017	6,467	(450)
5	Exchanges - Base	6,628	4,000	2,628
6	Exchanges - Net RAM	19,859	6,997	12,862
7	C1 Rebate Program	-	-	-
8	M13 Transportation	152	182	(30)
9	M16 Transportation	287	312	(25)
10	Other S&T Revenue	513	533	(20)
11	Total Transportation Revenue	106,976	91,813	15,163
	Storage			
12	Short-term Storage Services	5,834	3,125	2,709
13	Off-Peak Storage/Balancing/Loan Services	1,259	1,250	9
14	Total Storage Revenue	7,093	4,375	2,718
15	Total S&T Revenue	114,069	96,188	17,881

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit H1, Tab4- Average Use Per Customer (Deferral Account No. 179-118)

a) Clarify exactly Union is proposing for 2013.

b) Will the AU account record differences from forecast as in the past or is 2013 considered a Cost of Service Year where such mechanisms are not usually approved?

c) What is the sensitivity of the 2013 Revenue Requirement to a 1% change in AU forecast for the General Service classes?

d) Does continuing the AU deferral account decrease Unions Weather related Business and Financial risk relative to a Cost of Service year without DA protection?

Response:

a) Union is proposing to eliminate the wording that limits the account's applicability to 2008 through 2012.

b) The AU account will not record differences from forecast for 2013 because 2013 is a cost of service year. The earliest that the AU deferral account would be used is in relation to 2014, assuming that there is an incentive regulation framework in place at that time and that the AU true-up is a feature of that framework.

c) Please see the response to b) above.

d) Please see the response at Exhibit J.DV-4-2-2.

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2011-0210**

VOLUME:	**8**	
DATE:	**July 24, 2012**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

MR. SMITH: Maybe just following up on that, Ms. Elliott, is the presence of negative short-term debt, is this the -- is this the first time this has occurred in Union's utility capital structure?

MS. ELLIOTT: No, it's not. It's been in the capital structure for at least the past two rate cases, 2007 and 2004.

MR. SMITH: Thank you. I have no further questions in cross-examination -- or examination-in-chief.

MS. HARE: Thank you.

Mr. Aiken, are you cross-examining first?

CROSS-EXAMINATION BY MR. AIKEN:

MR. AIKEN: Yes. Thank you, Madam Chair.

Good morning, panel. My name is Randy Aiken. I'm here representing the London Property Management Association. I've got a couple of questions or a couple of areas I want to ask questions on, and you will need the LPMA compendium part 2, which is Exhibit K6.6.

If you could turn to page 9 of the compendium, this is Exhibit J.DV-4-2-1, I have a few questions related to the average use per customer deferral account.

Based on the response provided to this interrogatory, Union indicates that there is no need to keep this account in 2013. So am I correct that Union does not intend for this account to be used in 2013?

MS. ELLIOTT: That's correct, yes.

MR. AIKEN: But you want to keep it around because it might be a possible component of your next multi-year incentive regulation proposal; is that correct?

MS. ELLIOTT: That's correct.

MR. AIKEN: Could you turn to page 4 of the compendium? This is appendix C from Exhibit H1, tab 4, and is the actual wording in the average use per customer account. I want to read the middle part of it.

It says:

> "To record as a debit or credit in deferral account number 179-118 the margin variance resulting from the difference between the actual rate of decline in use per customer and forecast rate of decline in use per customer included in gas delivery rates as approved by the Board. Actual and forecasted rate of declines in use per customer will be calculated on a percentage and rate class-specific basis for rate classes M1, M2, 01 and 10, be normalized for weather and exclude the impacts attributed to DSM which are captured in the Lost Revenue Adjustment Mechanism deferral account number 179-75."

Now, there does not appear, to me at least, to be anything in that wording that indicates that this account will not be used in 2013; would you agree with that?

MS. ELLIOTT: Yes, I would.

MR. AIKEN: Now, if we go if to page -- back to page 11 -- or sorry, to page 11 of the compendium, the last page, this is page 3 of Exhibit H1, tab 4, and it is a section that deals with the average use account. And it's described there.

This evidence indicates that you proposed to continue tracking the average use per customer in the existing deferral account, and to remove the limitation that currently makes it applicable only to the current incentive regulation period, 2008 to 2012.

Then it goes on to state that the proposed accounting order -- which is reflected in appendix C, which we just looked at, will allow it to be in effect until it is changed or eliminated.

Now, this evidence seems to contradict your earlier statement that it would not be used in 2013. So my question is: What wording changes are you proposing to the deferral account so that it is clear that it's not used in 2013?

MS. ELLIOTT: I think one of the possible wording changes would be to put a 2014 effective date on it.

MR. AIKEN: Then my question for that is -- Union is likely to be in for some sort of incentive, some sort of IRM proposal, probably later this fall.

So my question is: Why do we need to even keep that account around?

MS. ELLIOTT: Technically we don't. We could eliminate the account for the 2013 test year and reintroduce the account for the IRM period.

MR. AIKEN: Assuming it was part of the IRM proposal?

MS. ELLIOTT: Assuming it was part of the proposal, yes.

UNION GAS LIMITED

Accounting Entries for
Short-term Storage and Other Balancing Services
Deferral Account No. 179-70

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 570 Storage and Transportation Revenue
Credit	-	Account No. 179-70 Other Deferred Charges - Short-term Storage and Other Balancing Services

To record, as a debit (credit) in Deferral Account No. 179-70 the difference between actual net revenues for Short-term Storage and Other Balancing Services including; Peak Short-Term Storage underpinned by excess utility storage assets, Off-Peak Short-Term Storage, Gas Loans and Supplemental Balancing Services and the net revenue forecast for these services as approved by the Board for ratemaking purposes.

Debit	-	Account No.179-70 Other Deferred Charges - Short-term Storage and Other Balancing Services
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-70, interest on the balance in Deferral Account No. 179-70. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2011-0210**

VOLUME:	**5**	
DATE:	**July 17, 2012**	
BEFORE:	**Marika Hare**	**Presiding Member**
	Paul Sommerville	**Member**
	Karen Taylor	**Member**

MR. BROEDERS: No, it does not. Sorry, includes working capital, but does not include construction work-in-progress.

I may have misstated that. I apologize.

MR. SHEPHERD: Then let's go down to the last section, and this is the equity section.

You're asking for a 40 percent equity ratio, but you're asking for 40 percent plus the preferred equity, right? You're treating the preferred equity as not equity for this calculation?

MR. BROEDERS: We are asking for 40 percent common equity component to the shareholder. The preferred equity is external to Spectra, the shareholders.

MR. SHEPHERD: Why would that make a difference?

MR. BROEDERS: We're requesting 40 percent for the common equity.

MR. SHEPHERD: Why would it make a difference that somebody else holds the preferred equity?

MR. BROEDERS: It is viewed more as debt than equity.

MR. SHEPHERD: It is not debt, though. It is equity.

MR. BROEDERS: Okay.

MR. SHEPHERD: So, in fact, the cost of the 3.50 percent, you have to gross that up for tax, right?

MR. BROEDERS: Oh, yes, we do.

MR. SHEPHERD: Okay. And do you disagree with the calculation of 273 million as the cost, if you're using the structure that the electricity distributors use?

Will you accept that number as being a correct

calculation, subject to check?
MR. BROEDERS: Yes, I will.
MR. SHEPHERD: Thank you.
Now, I wonder if you could go to page 6 of our materials, and I think these -- just a couple of questions are for you, Mr. Fetter.
You have a number of -- this is an excerpt from your report.
MR. FETTER: Yes, sir.
MR. SHEPHERD: And you have a number of comments on how important it is that the regulator -- how much the investors and the rating agencies look at the regulator and what the regulator says, right?
MR. FETTER: In the utility sector, yes.
MR. SHEPHERD: Okay. And we can agree that what this Board says is important to the rating agencies, right?
MR. FETTER: Very much so.
MR. SHEPHERD: Can we also agree that the Ontario Energy Board is known throughout -- by the rating agencies as providing a very stable and strong regulatory backup to its utilities?
MR. FETTER: Yeah. I think pretty positive.
MR. SHEPHERD: And indeed, in your report you have included a number of quotes from rating agencies. And in fact, whenever we see rating reports, one of the things we see in an Ontario utility is: great regulator. They really give them lots of support. It's true, right?
MR. FETTER: Pretty positive, yes.

MR. SHEPHERD: And that reduces the financial risk of the utilities; correct? Does it reduce the financial risk or the business risk? Which?

MR. FETTER: It has an impact on risk across the board.

MR. SHEPHERD: All right. So, then, just two other brief questions.

The first, I guess, is also to you, Mr. Fetter. We have included an excerpt from the transcript on pages 10 and 11 of our materials.

MR. FETTER: I have it, yes.

MR. SHEPHERD: You talked about this earlier today with Mr. Warren, and I am not going to go through that again, but I just want to ask you something about this.

Do I understand you to be saying in your answers here that, in effect, the additional cost to ratepayers of the proposed higher equity thickness is sort of like an insurance premium to cover the risk associated with a bad thing happening in the financial markets? Is that a reasonable analogy?

MR. FETTER: I would describe it more as bringing this utility up into a mainstream financial position, so that if a very negative event affected the economy at large or the regulated sector, specifically, then Union Gas would not be an outlier and subject to negative occurrences vis-à-vis its investor -- the investors that it needs to fund its operations.

MR. SHEPHERD: Okay. That doesn't look like what you said. It looks like what you said is -- because you were asked what's the benefit to the ratepayers, and I think what you said is the benefit to the ratepayers is this will improve Union's prospects during a financial crisis; isn't that what you said?

MR. FETTER: It would assure their ability to go to market. I think, as Professor Vander Weide said earlier, you know, taking it to the absurd, to use as an example, if you went to 100 percent debt, it would be incredibly less costly than having an equity component, but the customers or ratepayers would probably end up counting those savings probably in a very cold room by candlelight.

[Laughter]

MR. SHEPHERD: I'm sorry, I guess I'm...

Whenever a cost of capital expert says if you don't do what the utility wants the world will come to an end, I think it is a bit overstatement.

MR. FETTER: No. I said an example where 100 percent debt would be the least costly capital structure, but it is ridiculous to even consider.

So what you do is try to strike a fair balance between the debt and equity to ensure that no matter the capital market conditions, including a global financial crisis like we saw in 2008/2009 that I think nobody in the world predicted except one guy on Wall Street who made billions of dollars, you need to put Union Gas in the same stead as the mainstream of the regulated utility sector so that it can have access to the markets, even if we see a financial

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit C1, Tab 7 and Exhibit H1, Tab 4, Appendix C

Union noted that following the NGEIR Decision (EB-2005-0551) Union's practice has been to sell its non-utility storage space on a long-term basis and to sell the excess utility space on a short-term basis. Despite this practice, Union is authorized by the Board to sell non-utility storage space under short-term contracts and retain 100% of the revenues.

Union proposed that when it sells short-term peak storage services using non-utility storage space, the total margins received from the sale of all peak short-term storage be allocated to ratepayers and shareholders based on the utility and non-utility share of the total quantity of peak short-term storage (less than 2 years) sold each calendar year.

Union noted that it is able to give effect to its proposal due to its ability to track what storage assets are being used for each type of storage transaction. At p. 5 of the Board's Decision on Rate Order in EB-2011-0038, the Board indicated that:

"… the Board's findings are informed by Union's ability to track what storage assets are being used for each type of storage transaction and state that the entire amount of utility storage above in-franchise requirements is available for sale as short-term storage services (and all costs of this space is to be paid for by in-franchise customers)."

Union noted that the proposed change does not impact ratepayers. Going forward, Union will continue to sell all excess annual utility storage as short-term peak storage, and likewise 90% of all margins from C1 Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing Services, and C1 Firm Short-Term Deliverability will accrue to ratepayers. Union proposed to modify the Short-term Storage and Other Balancing Services accounting order to specify that the revenues are associated with the excess utility space. (Para 1)

Union's proposed revised description for the Short-term Storage and Other Balancing Services Deferral Account is as follows:

To record, as a debit (credit) in Deferral Account No. 179-70 the difference between actual net revenues for Short term Storage and Other Balancing Services including; Peak Short-Term Storage underpinned by excess utility storage assets, Off-Peak Short-Term Storage, Gas Loans and Supplemental Balancing Services and the net revenue forecast for these services as approved by the Board for ratemaking purposes. (Para 2)

a) Please discuss whether Union is planning on selling non-utility storage space as short-term peak storage services in the future. Please highlight whether this is a change from Union's past practices.

b) Please explain why Union can not track only the short-term storage transactions which rely on excess utility storage space and include the entirety of those transactions in the Short Term Storage Deferral Account for margin sharing with ratepayers. Please explain why Union is proposing to use a proportional approach for allocating margins to shareholders and ratepayers.

c) Please explain if and how Union's proportional approach operates to record amounts for sharing in the Short Term Storage Deferral Account. Please provide an example using the 10PJ / 13PJ scenario provided in Union's evidence at Exhibit C1, Tab 7.

d) Please explain the differences in language between stating that 90% of all margins from C1 Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing Services, and C1 Firm Short-Term Deliverability will be accrue to ratepayers (Paragraph 1 cited in the preamble) and what is stated in Paragraph 2 (also cited in the preamble).

e) Does Union agree that the following description for the Accounting Order is more transparent:

   To record, as a debit (credit) in Deferral Account No. 179-70 the difference between actual net revenues for Short term Storage and Other Balancing Services including; Peak Short-Term Storage underpinned by the excess utility storage assets (above utility requirements and below the 100 PJ fixed utility asset), Off-Peak Short-Term Storage, Gas Loans and Supplemental Balancing Services and the net revenue forecast for these services as approved by the Board for ratemaking purposes.

Response:

a) Subject to the Board's approval of Union's proposed approach to sharing revenue from the sale of short-term peak storage services and the appropriate market conditions, Union will sell short-term peak storage service using non-utility space. This is a change from Union's past practices.

b) Union is able to trace the individual short-term peak storage transactions and could assign the individual storage transactions as utility transactions or non-utility transactions. Rather than assigning individual transactions as utility or non-utility, Union has proposed to proportion total short-term peak storage revenue based on the utility/non-utility share of the total quantity of short-term peak storage sold to avoid any opportunity for Union or ratepayers to be advantaged relative to the other due to timing of the transactions.

c) Union's proportional approach will allocate the net revenues, related to short-term peak storage services between utility and non-utility sales. The portion allocated as utility sales will be the amount recorded in the deferral account.

   Each year the excess utility storage will be compared to the total sales of short term peak storage. That ratio will then be applied to the total net revenues from short-term peak storage and that amount will be included for deferral in account 179-70. The remainder of the net revenue from short-term peak storage would accrue to the shareholder as it was generated using non-utility storage assets.

   Please see Attachment 1 for a numerical example.

d) 90% of all margins from C1 Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing Services, and C1 Firm Short-Term Deliverability arising from the sale of excess utility space will accrue to the ratepayer. Excess utility space is the difference between 100 PJ and the in-franchise storage requirement (EB-2005-0551 Decision, pp. 101-103).

   Non-utility space is all space in excess of the 100 PJ and all revenues, whether short-term or long-term, accrue to the Company (EB-2005-0551 NGEIR Decision, pp. 103-104).

e) Union confirms the description provided for the Accounting Order is more transparent.

UNION GAS LIMITED
Southern Operations Area
Example of Allocation of Short Term Peak Storage Sales between Utility and Non-Utility

Line No.	Particulars		Utility Storage Space (PJs)	Short Term Peak Storage Sold (PJs)	Revenue from Short Term Peak Storage ($ millions)
1	Net Revenues from Short Term Peak Storage	(1)			8.00
2	Total Short Term Peak Storage Sales			13.0	
3	Storage Space reserved for Utility		100.0		
4	Utility Storage Space Requirement	(2)	90.0		
5	Excess Utility Storage Space (Line 3 - Line 4)		10.0		
6	Total Utility Short Term Peak Storage Sales (Line 5)			10.0	
7	Total Non-Utility Short Term Peak Storage Sales (Line 2 - Line 6)			3.0	
8	Short Term Peak Storage Net Revenues - Utility (Line 1 * (Line 6 / Line 2))	(4)			6.15
9	Short Term Peak Storage Net Revenue - Non Utility (Line 1 * (Line 7 / Line 2))	(5)			1.85

Notes:
(1) Total net revenues from sales of short term peak storage services for the calendar year.
(2) Total in-franchise storage space requirement for October 31 of calendar year.
(3) All values, with the exception of "Storage Space Reserved for Utility", are for illustrative purposes and are neither actual or forecast.
(4) Short Term Peak Storage net revenues available for deferral.
(5) Short Term Peak Storage related to non-utility storage excluded from deferral calculations.

UNION GAS LIMITED

Answer to Interrogatory from
Federation of Rental-Housing Providers of Ontario ("FRPO")

Ref: Exhibit H1, Tab 4, Appendix C

The proposed wording for Deferral Account No. 179-70 refers to Peak Short-Term Storage services that are provided from "excess utility storage assets".

a) How does Union define "excess utility storage assets" in this context?

b) Why does Union propose to exclude revenue from Peak Short-Term Storage services provided from utility storage assets that are not included in the definition of "excess utility storage assets"?

c) Would Union agree to change the proposed wording from "excess utility storage assets" to "utility storage assets"? If Union would not agree to this change, please provide an explanation.

Response:

a) Excess utility storage assets is the difference between the storage space required by the utility for the upcoming storage year and the 100 PJ of storage space reserved for utility use.

b) Union's current practice is to sell Short-term Peak Storage Services from excess utility assets. Please see the response at J.DV-1-1-1 for Union's proposal.

c) No, it is not appropriate to change the proposed wording. It is only the net revenue earned on the "excess" utility storage assets that are subject to deferral and sharing.

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit H1, Tab 4, pages 2-3, Updated

Union is proposing to change the working in Account No. 179-70 for Short-term Storage and Other Balancing Services to reflect an updated list of revenues included in the account.

a) Are there any sources of revenue that Union is aware of that may materialize in the future that would be based on the use of utility storage space in excess of in-franchise requirements up to the 100 PJ of space that is not included in the proposed list of revenues? If yes, please provide details and explain why Union has not included these revenues in the proposed list.
b) Does Union agree that any source of revenue that is received based on the use of the regulated utility storage space that is not included in the proposed list should be included in the deferral account? If not, please explain why not.

Response:

a) No.

b) Union expects to sell the space in excess of in-franchise requirements up to 100 PJ on a short term basis. The net revenue from these transactions would be deferred and shared with rate payers.

PREFILED EVIDENCE

PATTI PIETT, DIRECTOR, STORAGE AND TRANSPORTATION SALES

CAROL CAMERON, MANAGER, CAPACITY MANAGEMENT AND UTILIZATION

The purpose of this evidence is to address Union's proposed method for altering short-term storage margin between its utility and non-utility storage operations.

Sale of Non-Utility Storage Space

Following the NGEIR Decision (EB-2005-0551) Union's practice has been to sell its non-utility storage space on a long-term basis and to sell the excess utility space on a short-term basis. Despite this practice, Union is authorized by the Board to sell non-utility storage space under short-term contracts and retain 100% of the revenues. As the Board held at p. 101 of the NGEIR Decision (EB-2005-0551):

> *"The Board finds that the entire margin on storage transactions that are underpinned by "utility asset" storage space, less an appropriate incentive payment to the utilities, should accrue to ratepayers. Ratepayers bear the cost of that space through the regulated storage rates and should benefit from transactions that utilize temporarily surplus space. The Board finds that shareholders will retain all of the margin on short-term transactions arising from the "non-utility" storage space." [Emphasis added]*

Consistent with NGIER, if Union sells short-term peak storage services using non-utility storage space, Union proposes that total margins received from the sale of all peak short-term storage be allocated to ratepayers and shareholders based on the utility and non-utility share of the total quantity of peak short-term storage (less than 2 years) sold each calendar year.

For example, if the excess utility storage space is determined to be 10 PJ effective for 2012 (as determined by Union's ISP plan) and Union sells a total of 13 PJ of peak short-term storage, then the allocation of margins would be 10/13 to the utility ratepayers and 3/13 to the shareholder. This methodology is transparent to all participants and will yield the same proportionate return on all short-term transactions for the ratepayers and the shareholders.

Due to the seasonal volatility and variability of market-priced storage Union cannot predict what period of time will yield the highest or lowest prices for short-term peak storage services. The use of a proportionate share of calendar year margins ensures that neither party is impacted by the timing of storage sale, or fluctuations to storage values throughout the year. Both parties will be treated equitably in this proposal.

Union is able to give effect to its proposal due to its ability to track what storage assets are being used for each type of storage transaction. At p. 5 of the Board's recent Decision on Rate Order in EB-2011-0038, the Board indicated that:

> *"… the Board's findings are informed by Union's ability to track what storage assets are being used for each type of storage transaction and state that the entire amount of utility storage above in-franchise requirements is available for sale as short-term storage services (and all costs of this space is to be paid for by in-franchise customers)."*

Union's proposed change does not impact ratepayers. Going forward, Union will continue to sell all excess annual utility storage as short-term peak storage, and likewise 90% of all margins from C1 Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing Services, and C1 Firm Short-Term Deliverability will accrue to ratepayers. Union proposes to modify the Short-term Storage and Other Balancing Services accounting order to specify that the revenues are associated with the excess utility space. Please see the evidence at Exhibit H1 Tab 4.

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

UNION'S 2013 RATE REBASING APPLICATION: STORAGE AND TRANSPORTATION ISSUES

EB-2011-0210

Prepared for

Canadian Manufacturers & Exporters (CME)
Consumers Council of Canada (CCC)
The Corporation of the City of Kitchener (CCK)
Federation of Rental-housing Providers of Ontario (FRPO)

By

John A. Rosenkranz

May 16, 2012

ratepayers. Limiting the sale of utility storage services to a single class of transactions—short-term peak storage services—is inconsistent with this objective. Union should consider all available options for optimizing the value of these storage assets, including third-party asset management arrangements.

Proposed Allocation of Short Term Peak Storage Revenue

Recommendation 9: Union's proposal to allocate Short Term Peak Storage revenue between utility storage and non-utility storage should be rejected.

In its March 27, 2012 update filing, Union included a new proposal to allocate total Short Term Peak Storage revenue between utility storage and non-utility storage on a calendar year basis. Under Union's proposal, Excess Utility Storage Space would be sold as Short Term Peak Storage and Union would sell additional Short Term Peak Storage from its non-utility storage assets. The total Short Term Peak Storage revenue for each calendar year would be allocated pro-rata between utility storage and non-utility storage.

Union's proposal is seriously flawed. First, it would require all Excess Utility Storage Space to be sold as Short Term Peak Storage, even if this was not the best way to create value for utility ratepayers. Second, even though Union says that the intent of the proposal is to "avoid any opportunity for Union or ratepayers to be advantaged relative to the other due to timing" of storage transactions,[16] this proposal would create a strong incentive for Union to sell additional Short Term Peak Storage service from non-utility assets if the value of storage falls during the year. By selling additional Short Term Peak Storage from non-utility storage space later in the year, when market prices are lower, Union's non-utility storage business would capture revenue from utility storage by diluting the value of utility storage sales that were made earlier at higher prices.

Union's proposal is also unnecessary. Even though Union's storage assets are operated on an integrated basis, Union is still able to tie an individual storage transaction to either the utility storage account or the non-utility storage account.[17] Concerns that utility

[16] Exhibit J.DV-1-1-1

[17] "Union is able to trace individual short-term peak storage transactions and could assign the individual storage transactions as utility transactions or non-utility transactions." (Exhibit J.DV-1-1-1)

ratepayers will be disadvantaged by allowing Union's non-utility storage business to market utility storage assets can be better addressed by other means.

D. Deferral Account No. 179-70

Recommendation 10: The definition of Deferral Account No. 179-70 should be based on the assets used to create the storage revenue, not the type of transaction.

Union proposes to modify the description of the Short-term Storage and Other Balancing Services Deferral Account. However, the wording proposed by Union is unnecessarily restrictive. In particular, Union would exclude margin sharing on short-term storage revenue obtained from optimizing utility storage space that is not Excess Utility Storage Space.[18] This is the storage that Union plans to use for in-franchise requirements, but which can often be sold as short-term storage and balance services on a seasonal or "as available" basis. Storage and balancing service sales from these "required" utility storage assets are the Union counterparts to Enbridge's Transactional Services storage sales.

Under the current regulatory regime, what matters is the assets that underpin the storage transaction, not whether the primary term of transaction is greater or less than two years. Net revenues on all storage and balancing transactions that use utility storage assets should be credited to ratepayers. The deferral account definition should not be limited to any specific types of transactions, and should give Union the flexibility to optimize utility storage assets using the best available methods.

Based on these principles, the definition of Deferral Account No. 179-70 should be modified as follows:

1. In the title, change "Short-term Storage" to "Storage".

2. Substitute the following language:

"To record, as a debit (credit) in Deferral Account No. 179-70 the difference between the actual net revenues for Storage and Other Balancing Services underpinned by utility storage assets including, but not limited to, Short-Term Peak Storage, Off-Peak Short-

[18] "It is only the net revenue earned on the 'excess' utility storage assets that are subject to deferral and sharing." (Exhibit J.DV-4-10-1)