UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit C1, Tab 1, page14

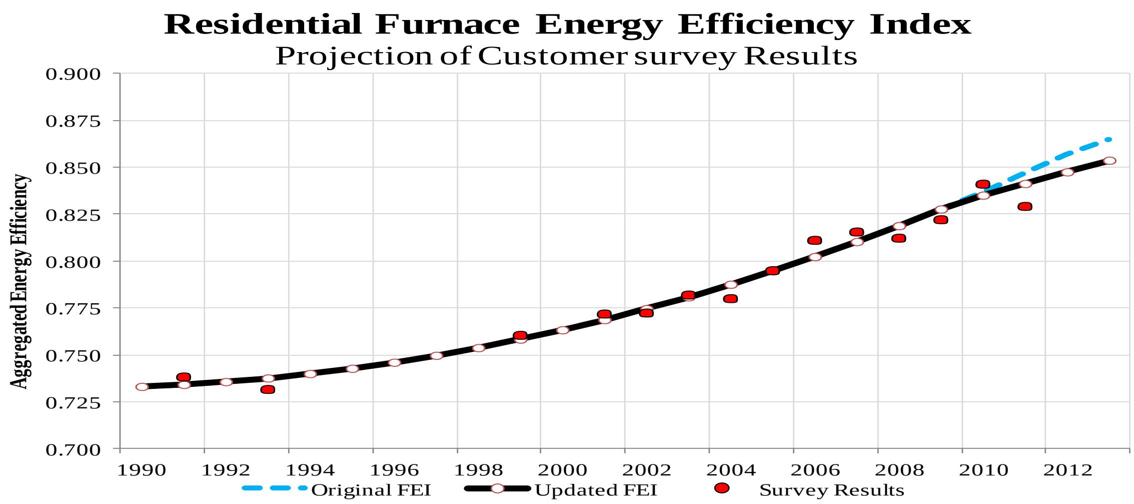
Union's evidence on page 14 of Exhibit C1/Tab 1 indicates that after weather, the weighted furnace efficiency variable is the second most important factor in explaining residential natural gas consumption. Please provide furnace efficiency numbers from 2002 to 2011.

Response:

The Furnace Efficiency Index ("FEI") variable is an estimate obtained from 14 residential surveys undertaken over the period 1991 to 2011. The annual FEI values on an annual basis are plotted in the chart below and provided in tabular form.

The FEI variable is a weighted estimate of total furnace stock energy efficiency based on the efficiency of three furnace types: conventional, mid and high efficiency furnaces. The respective average furnace utilization efficiency ("AFUE") of the three furnace types is: 60%, 80% and 95%. These weighted efficiency measurements provide the basis for estimating the underlying energy efficiency trend for the historic period (represented by a fitted line).

For the forecast period the fitted line is projected according to a furnace stock adjustment calculation. The stock adjustment considers the impact on the weighted efficiency of new high efficiency furnaces being installed in new homes and conversions, as well as furnace replacements in existing homes. In the regression analysis the survey based FEI estimate is transformed and restated as an energy loss. The mathematical identity is: Energy Loss = 1 less the survey FEI value.



Please see the response at Exhibit J.C-1-1-2-a (i to iii) for more discussion on the FEI variable.

Year	Original FEI	Updated FEI	Survey Results
1990	0.733	0.733	
1991	0.734	0.734	0.738
1992	0.736	0.736	
1993	0.738	0.738	0.732
1994	0.740	0.740	
1995	0.743	0.743	
1996	0.746	0.746	
1997	0.750	0.750	
1998	0.754	0.754	
1999	0.758	0.758	0.760
2000	0.763	0.763	
2001	0.769	0.769	0.772
2002	0.775	0.775	0.772
2003	0.781	0.781	0.782
2004	0.788	0.788	0.780
2005	0.795	0.795	0.795
2006	0.802	0.802	0.811
2007	0.810	0.810	0.816
2008	0.819	0.819	0.812
2009	0.828	0.828	0.822
2010	0.837	0.835	0.841
2011	0.847	0.841	0.829
2012	0.857	0.848	
2013	0.865	0.854	

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit C1, Tab 1, page 23

In the Application, Union indicates that the Normalized Average Consumption ("NAC") forecast for residential customers continues to decline over the 2010 to 2013 period and essentially resembles the trend observed over the past 20 years. Please answer the following questions related to declining NAC within the residential segment:

a) The trend in the NAC seems to be declining over a fairly long period. Has Union conducted any research or analysis to understand when the trend may eventually flatten out? Please provide a detailed response and any opinions that Union may have on this subject matter.

b) In Union's update filed on March 27, 2012, the 2011 forecast number for residential rate M2 has been changed from 2,227 to 2,264 cubic meters which represents the actual number. In other words, the decline is not as steep as estimated. Why does Union believe that in 2012 the decline is going to be fairly significant, from 2,264 to 2,199 cubic meters?

Response:

a) The furnace stock adjustment calculation provides an estimate of when in the future the normalized average consumption ("NAC") may plateau. A projection of the FEI variable indicates that the level of 95% is reached sometime during the period 2025 to 2030. The NAC would flatten as well. This projection assumes that:

- The projection starts in 2012 incorporating the 2011 actuals.
- Each year the projection assumes there are 20 to 24 thousand new customers (1.4% annual growth rate).
- 28 to 32 thousand existing residential customers replace their obsolete furnaces.
- Energy prices do not change significantly as total energy bills effect consumption.
- High efficiency furnace technology and building envelope technology does not materially change from today's technology. For example, a 20% improvement could move the plateau forward about 2 to 3 years.

b) The 2011 difference between the forecast average use and the NAC for the southern residential customers was 1.7%, or 37 cubic metres per customer.
This gross 1.7% forecast error is reduced to a residual 1% error, or 22 cubic metres, when the actual values for the demand drivers (furnace efficiency, persons per household, total bill amounts and the impacts of DSM) are recognized, and replace the assumed values used in the

estimation. The residual error is not explained by the regression equation. It may be attributable to other consumer behaviour, e.g. higher thermostat settings associated with low customer bills arising from warm weather and low gas prices. A 1% forecast error is considered a reasonable forecast error, as it falls well within the 2% forecast error band.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit C1, Tab 1, Appendix A, page16

In Appendix A of Exhibit C1/Tab 1, Union has provided an Ex-Post analysis for 2010 with the Annual Estimate Percent Error. The Error for Industrial rate classes is 21.1%. Please provide a breakdown based on rate classes for the Industrial segment.

Response:

The annual estimated error of 21.1% was miss-calculated. The correct Annual Estimate Percent Error is 17.8%.

The ex-post forecast error of 17.8% for the total industrial demand equation for the general service market reflects:

- A three year lag estimate for the year 2010 with the last historic year being 2007.
- The assumption of no economic recession occurring during the forecast horizon.

The ex-post regression analysis did not include the economic recession dummy variables that are included in the demand forecast equation used to prepare the 2013 energy demand forecast. The two dummy variables in the demand forecast equation account for large residual variances in the regression analysis that occurred during Q4 2009 and Q1 2010 and for a structural shift beginning in 2008. Their timing reflects the economic recession conditions present during 2008 to 2010. Including these two dummies in the ex-post analysis reduces the forecast error for three-year ahead forecast to 3.7%.

The forecast variance error by rate class in the ex-post analysis is as follows:

	Corrected	Including Dummy Variables
Rate M2 former:	17.7%	3.7%
Rate 10 Banner Industrials:	17.2%	3.6%
Rate 10 LIB/CIA:	19.0%	3.9%
Total:	17.8%	3.7%

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit C1, Tab 1, Appendix A, page 4

The Update to Table 3 showing customer attachments across all rate classes for 2011, 2012 and 2013 indicates a significant difference between actual and forecasted attachments for Rate 10. The forecast filed in November showed 10 attachments versus an actual number of 31 for 2011. Please explain the significant difference and whether this number impacts forecasts for 2012 and 2013.

Response:

Rate class migration for northern commercial customers between Rate 10 and Rate 01 resulted in the increase in attachments from 10 to 31. Rate class migration is variable as to size and timing, and as such Union does not consider a change to the Rate 10 commercial billed customer forecast to be required.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit C1, Tab 1, Appendix A, page 4

a) What is the accuracy of Union's general service customer forecast for the Budget Years 2008, 2009 and 2010? Please provide reported actual and forecasted values.

b) Please indicate the level of customer shrinkage that was assumed in the forecasts above.

Response:

a) The table below shows the accuracy of the billed customer forecast over the period 2008 to 2011. In percentage terms variances are small and range from 0.6% in 2008 to 0.2% in 2009.

General Service Rates: Total Billed Customers at December 31st

Year	Actual	Budget	Variance
2008	1,308,905	1,301,470	7,435
2009	1,324,543	1,326,897	(2,354)
2010	1,343,305	1,335,674	7,631
2011	1,359,576	1,355,277	4,299

The average variance of the four budgets is 4,253.

b) Customer shrinkage is measured monthly and trended on an annual basis. Data indicates that on a monthly basis, customer shrinkage is highly variable. The annual trend since 2003 is for shrinkage to become smaller over time, from about 7,000 at the end of 2003 to about 2,000 by December 2011. Customer shrinkage for the years 2008 through 2011 is provided below.

Total Customer Shrinkage at December 31

Year	Actual	Budget	Variance
2008	4,046	5,575	1,530
2009	1,992	3,725	1,733
2010	1,210	4,214	3,004
2011	3,006	2,200	(806)

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 1, Table 1, Updated

The footnote to Table 1 indicates that the 2010 actual throughput volumes are weather normalized according to the 2013 weather normal which is based upon the 20-year declining trend weather normal methodology.

a) Please clarify whether the 2010 actual throughput volumes have been normalized to the same degree forecast level as used to forecast 2013 (i.e. 3,599 and 4,626 degree days, respectively for the south and north) or whether the 2010 actual throughput volumes have been normalized to a level of heating degree days that would have been forecast for 2010 had the 2013 degree day forecasting methodology been used. If the latter, please provide the 2010 degree days figures used for normalization purposes.

b) Please provide the weather normalized throughput in the same level of detail for rate & service customer class shown in Table 1 for 2007 through 2011 and the forecast for 2012 and 2013, using the 2013 forecast of degree days (3,599 for south, 4,626 for north).

Response:

a) The 2010 actual throughput volumes have been normalized to the same degree forecast level as used to forecast 2013.

b) Please see Attachment 1.

Filed: 2012-05-04
EB-2011-0210
J.C-1-2-1
Attachment 1

Line No.	Rate & Service Customer Class	Total W.N. Throughput 2007 Act.	Total W.N. Throughput 2008 Act.	Total W.N. Throughput 2009 Act.	Total W.N. Throughput 2010 Act.	Total W.N. Throughput 2011 Act.	Total W.N. Throughput 2012 Frcst.	Total W.N. Throughput 2013 Frcst
1	Residential Rate M1	2,139,815	2,145,457	2,111,558	2,134,240	2,144,466	2,113,728	2,094,387
2	Residential Rate M2		3,453	4,010	3,870	4,001	3,690	3,603
3	Residential Rate 01	639,272	646,692	641,283	632,954	642,479	635,250	629,860
4	Commercial Rate M1	1,286,297	638,496	614,590	582,100	626,357	717,495	713,366
5	Commercial Rate M2		703,565	710,025	722,054	770,529	609,463	605,387
6	Tobacco Rate M1	15,353	7,508	7,910	13,834	13,106	10,726	9,979
7	Tobacco Rate M2		3,633	3,149	4,381	5,444	2,476	1,956
8	Commercial Rate 01	205,174	224,469	221,964	223,455	232,758	226,685	225,737
9	Commercial Rate 10	231,251	227,467	226,596	220,661	245,429	228,224	227,264
10	Industrial Rate M1	435,649	65,946	55,956	52,285	56,399	59,073	58,679
11	Industrial Rate M2		365,835	344,091	304,737	333,171	346,446	345,706
12	Industrial Rate 10	43,087	42,180	44,528	40,753	47,300	39,501	38,874
13	Industrial L.I.B, Rate 10	77,856	72,950	65,199	61,383	39,613	50,390	50,130
	Total Throughput Vol.	**5,073,753**	**5,147,652**	**5,050,857**	**4,996,707**	**5,161,053**	**5,043,146**	**5,004,929**
	By Service Class							
14	Residential	2,779,087	2,795,602	2,756,851	2,771,064	2,790,947	2,752,668	2,727,851
15	Commercial	1,738,075	1,805,139	1,784,233	1,766,485	1,893,624	1,795,068	1,783,689
16	Industrial	556,591	546,911	509,773	459,158	476,483	495,410	493,389

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 1, Table 3, Updated

a) Please expand Table 3 to reflect actual total billed customers for 2007 through 2011, along with the forecast for 2012 and 2013.

b) Based on the response to part (a) above and part (b) of the previous interrogatory, please provide a table that shows the average use per customer for each of the service/rate class categories shown in Table 3.

Response:

a) Please see the table below.

Total Billed General Service Customers at December

Line No.	Rate & Service Customer Class	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
1	Residential Rate M1	904,029	919,330	931,272	945,156	956,388	971,150	986,142
2	Residential Rate M2		32	38	35	32	35	35
3	Residential Rate 01	270,482	274,484	277,830	281,810	286,420	290,171	294,708
4	Commercial Rate M1	79,234	75,265	75,145	75,773	76,032	76,377	76,883
5	Commercial Rate M2		4,674	5,156	5,244	5,280	5,348	5,400
6	Tobacco Rate M1	846	785	743	747	719	732	725
7	Tobacco Rate M2		54	45	40	54	30	25
8	Commercial Rate 01	26,497	26,536	26,753	27,036	27,213	27,585	27,789
9	Commercial Rate 10	2,094	2,177	2,044	1,976	2,002	1,886	1,888
10	Industrial Rate M1	5,422	4,110	3,987	4,022	4,007	4,012	4,007
11	Industrial Rate M2		1,230	1,327	1,288	1,271	1,308	1,318
12	Industrial Rate 10	148	151	130	128	126	115	122
13	Industrial L.I.B, Rate 10	84	77	73	50	32	46	44
		1,288,836	1,308,905	1,324,543	1,343,305	1,359,576	1,378,795	1,399,086

b) Please see the table below.

NORMALIZED AVERAGE CONSUMPTION (NAC) m^3 per customer

Line No.	Rate & Service Customer Class	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013
1	Residential Rate M1	2,392	2,358	2,286	2,280	2,260	2,195	2,144
2	Residential Rate M2		105,799	120,123	107,593	123,152	105,423	102,936
3	Residential Rate 01	2,384	2,380	2,328	2,268	2,277	2,211	2,160
4	Commercial Rate M1	16,324	8,510	8,162	7,722	8,246	9,415	9,308
5	Commercial Rate M2		151,584	144,316	138,007	147,283	114,556	112,692
6	Tobacco Rate M1	17,613	9,570	10,453	18,565	18,097	14,578	13,728
7	Tobacco Rate M2		59,882	68,118	107,167	107,344	79,748	75,098
8	Commercial Rate 01	7,949	8,467	8,350	8,314	8,668	8,257	8,153
9	Commercial Rate 10	91,365	106,582	105,374	111,416	125,173	119,987	120,442
10	Industrial Rate M1	81,102	15,925	13,732	13,010	14,045	14,889	14,808
11	Industrial Rate M2		296,409	267,450	232,652	259,204	260,376	257,901
12	Industrial Rate 10	253,843	280,774	310,569	310,317	372,460	335,572	336,471
13	Industrial L.I.B, Rate 10	889,643	914,430	872,901	938,636	1,074,867	1,068,018	1,108,624
	Total NAC	3,975	3,971	3,842	3,754	3,830	3,688	3,610

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 1, pages 14-15, Updated

a) With respect to the furnace energy efficiency index (FEI), please provide the following:

i) a table that reflects the data points shown in Figure 2 for 1990 through 2013. If Union has a Survey Result for 2011, please also provide that figure.

ii) an explanation of how Union has estimated the FEI in those years that it does not have survey results.

iii) an explanation of how the forecast for 2012 and 2013 has been derived, including any equation used for this purpose, along with the regression statistics.

b) With respect to the persons per household estimates, please provide the following:

i) a table that reflects the data points used by Union for 1990 through 2013. If Union has a Survey Result for 2011, please also provide that figure. Please also indicate which data points are based on the survey results and which data points have been estimated.

ii) an explanation of how Union has estimated the persons per household in those years that it does not have survey results.

iii) an explanation of how the forecast for 2012 and 2013 has been derived, including any equation used for this purpose, along with the regression statistics.

Response:

a)

i) The historic and forecast FEI variable estimates are tabled in the 2013 REGN DATA FILE excel file. Refer to the Res. FEI Variable tab.

ii) The FEI variable in the historic years is set according to a fitted line. The fitted line passes through the FEI values obtained by annual surveys from 1991 to the present. It shows the increasing energy efficiency resulting from new high efficiency furnaces installed in new homes and replacements of obsolete furnaces in existing homes.

iii) The historic values for the survey FEI values are obtained by a fitted non linear line through the fourteen annual survey observations.

Based on the 2011 fitted line estimate, a furnace stock adjustment analysis then calculates the FEI values for the years 2012 and 2013. This analysis examines the change in the total portfolio of furnaces by furnace type: conventional (60% AFUE), mid efficiency (80% AFUE) and high efficiency (95% AFUE). The term AFUE means average furnace utilization efficiency.

The furnace stock is affected by new residential customer additions and the number of furnace replacements in existing homes. All new homes in Union's franchise, approximately 18,000, and all replacements, approximately 24,000 install high efficiency furnaces each year.

Union notes that in the regression analysis the FEI values described above are transformed. The transformed FEI variable is expressed as one less the survey FEI line fit value. This transformation enables a positive regression coefficient for the FEI variable.

b)

i) Please see the table below.

Year	Original PPH	Updated PPH	Survey Results
1990			
1991	3.278	3.265	3.230
1992	3.244	3.233	
1993	3.210	3.200	3.160
1994	3.176	3.168	
1995	3.142	3.136	
1996	3.108	3.103	
1997	3.074	3.071	3.200
1998	3.040	3.039	
1999	3.006	3.006	3.000
2000	2.971	2.974	3.000
2001	2.937	2.941	3.000
2002	2.903	2.909	2.900
2003	2.869	2.877	2.900
2004	2.835	2.844	2.700
2005	2.801	2.812	
2006	2.767	2.780	2.780
2007	2.733	2.747	2.720
2008	2.699	2.715	2.640
2009	2.664	2.682	2.730
2010	2.630	2.650	2.617
2011	2.596	2.618	2.703
2012	2.562	2.585	
2013	2.528	2.553	

ii) The persons per household estimate for all years during the historic period were obtained by using a fitted trend line through the available survey data points. The fitted line shows the declining number of persons per household over the historic period 1991 to the present.

iii) The estimated number of persons per household in 2012 and 2013 are projections of the fitted line based on data from the past 20 years.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 1, Figures 5 - 8, Original & Updated

For each of Figures 5 through 8, please explain the difference in the 2011 forecast average use as compared to the normalized actual use. For example, why is the actual residential old rate M2 normalized actual use of 2,264 m3 1.7% or 37 m3 higher than the 2011 forecast? How many months of actual data were included in the 2011 forecasts?

Response:

The difference between the forecast average use and the normalized actual use ("NAC") in 2011 is explained by:

- The variance between the actual and the assumed non weather related demand variables; and
- The regression residual estimate.

The non weather demand variables include furnace energy efficiency ("FEI"), persons per household ("PPH"), total bill amount, exchange rates ("FX"), fuel oil prices and the Demand Side Management ("DSM") related NAC impacts.

The table below provides a variance explanation of the observed usage variance for the four principal markets. A summary discussion on each market is provided below:

1. Southern residential customers: about 40% of the total positive 1.7% NAC variance is explained by the actual demand drivers. Variance in the FEI assumption is the largest factor. The remaining 1% difference (or 22 cubic metres per customer) is unexplained by the equation. The unexplained error is considered a reasonable forecast error as it falls below the 2% error band.
2. Northern residential customers: about 35% of the total negative 0.8% NAC variance is explained by the actual demand drivers. Variance in the FEI assumption is the largest factor. The remaining 1.4% difference (or -31 cubic metres per customer) is unexplained by the equation, but is considered as reasonable forecast error as it falls below the 2% error band.
3. Total commercial market: the total variance is 5.7% attributable to the other unexplained variance. The year 2011 saw another spike in usage, continuing a pattern seen since 2006. Normalized average consumption per customer was high in November and

December 2011 which depicts the presence of an agricultural process related load in the total customer mix. The normalized usage data for the first four months of 2012 was 8,887 m^3 per customer and since the first four months represent approximately 54% of the annual usage, this suggests that average usage will be below 16,500 m^3 per customer by year end. This confirms that 2011 commercial usage displayed another high year seen in the saw tooth pattern since 2006.

4. Total industrial market: the total variance was -2.8%, and is attributable to both the alternate fuel oil price and other factors.
5. In aggregate, the total NAC forecast accuracy in 2011for all 1.36 million general service customers was 1%.

The historical database underlying the statistical analysis for the forecast in evidence is:

- Residential South Use Eqn. monthly data from April 1993 to December 2010;
- Residential South Volume Eqn. monthly data from June 1995 to December 2010;
- Residential North Use Eqn. monthly data from April 1994 to December 2010;
- Residential Volume Eqn. monthly from May 1996 to December 2010;
- Commercial monthly data from January 1991 to December 2010; and
- Industrial quarterly data from Quarter 1,1997 to Quarter 4 2010.

The residential time periods provided improved regression fit and residuals results than using longer historical time periods.

With respect to the 2011 forecast usage and volume estimates presented in the four charts in the original evidence, the 2011 annual estimates are all forecast estimates. These estimates are weather normalized at the 2013 weather normal.

NAC FORECAST VARIANCE ANALYSIS - YEAR 2011

Residential South				
Year	Res M2 former Actual NAC	Res M2 former Forecasted NAC	NAC variance	% variance
	m^3	m^3	m^3	
2011	2,264	2,227	37	1.7%
NAC variance explained by:				
FEI			13	0.6%
PPH			1	0.0%
Total Bill			0	0.0%
DSM			1	0.0%
Other			22	1.0%

Residential North				
Year	Res 01 Actual NAC	Res 01 Forecasted NAC	NAC variance	% variance
	m^3	m^3	m^3	
2011	2,269	2,288	-19	-0.8%
NAC variance explained by:				
FEI			12	0.5%
PPH			2	0.1%
Total Bill			-1	-0.1%
DSM			-1	0.0%
Other			-31	-1.4%

Total Commercial Market				
Year	All Commercial Actual NAC	All Commercial Forecasted NAC	NAC variance	% variance
	m^3	m^3	m^3	
2011	17,006	16,092	914	5.7%
NAC variance explained by:				
Fall weather			-19	-0.1%
DSM			-7	0.0%
Other			940	5.8%

Total General Service Rate Industrial				
Year	All Industrial Actual VOL	All Industrial Forecasted VOL	VOL variance	% variance
	10^3 m^3	10^3 m^3	10^3 m^3	
2011	476,483	490,330	-13,847	-2.8%
Volume variance explained by:				
Exchange Rate			-2,246	-0.5%
HFO			29,505	6.0%
DSM			-490	-0.1%
Other			-40,616	-8.3%

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 1, Updated

a) Please update the general service forecast to reflect the latest forecasts available for the explanatory variables, actual 2011 data, total bill amounts based on the most recent Board-approved delivery and gas supply commodity rates and the DSM plan that results from the EB-2011-0327 proceeding. Please provide the total forecast throughput for 2013 in the same level of detail as shown in Table 1 and the total billed customer forecast for 2013 in the same level of detail as shown in Table 3.

b) Please provide the equations and regression statistics used in (a) above that include actual 2011 data.

c) Please provide all the historical and forecast data used in the updated forecast in an live Excel spreadsheet.

Response:

a) The general service forecast was updated to reflect all available 2011 actual data. The results are tabled below.

   The updated demand forecast incorporates the following analyses and revision to assumptions for the demand driver variables:

   1. The NAC forecast regression equations for residential , commercial and industrial markets were all updated to include 2011 actual data;
   2. The Residential demand variables that were updated included: Weather, FEI variable, PPH variable, Total Bill Amounts, and the DSM Plan NAC Impacts to reflect the 2012 2013 Settlement Agreement;
   3. The Commercial demand variables that were updated included: Weather, Harvest Variable and the DSM Plan NAC Impacts to reflect the 2012 2013 Settlement Agreement;
   4. The Industrial demand variables updated included: Weather, FX rate, Fuel Oil Price and the DSM Plan NAC Impacts to reflect the 2012 2013 Settlement Agreement;
   5. The weather normal was updated and reset to incorporate the 2011 actuals; this eliminates the three year regulatory lag present in the evidence forecast and restores a 2 year regulatory lag; and,

6. The billed customer forecast estimates for the residential, commercial and industrial markets were not changed even though:
   a) The provincial housing start estimates obtained from the March 2012 consensus for 2013 are lower, and customers may be over stated by 1,500 billed customers; and,
   b) The number of billed customers in the industrial market over the past four years have declined by an average of 55 customers per year and the forecast assumes an increase of 12 customers in 2013 over 2010 – a potential gap of about 120 customers.

The table below shows that the impact of the update scenario is an increase in total throughput volumes. Total throughput volumes are 10.8 million cubic metres or 0.2% above the original evidence for the year 2013. This difference is not material.

This comparative forecast scenario did not incorporate two major factors mentioned above related to the 2013 housing start estimates and the strong trend regarding customer losses in the industrial market. The impact of these two factors would lower total throughput in 2013 by about 16.5 million cubic metres. The industrial energy consumption that is lost is the major portion and is estimated at 10.8 million cubic metres. Should these factors occur, the demand forecast shifts back to slightly below the original evidence level for the test year.

TOTAL 2013 THROUGPUT VOLUMES: UPDATED FORECAST SCENARIO FOR 2011 ACTUALS

(in 10^3 m^3)

Rate & Service Customer Class	Total Throughput Original Frcst-2013	Change in volume due to DSM Plan	HFO & FX Rate Effect	Weather Normal	NAC	Total Throughput Updated Frcst-2013	% Diff
Residential Rate M1	2,094,387	5,445		(11,823)	16,623	2,116,456	1.1%
Residential Rate M2	3,603			(20)	42	3,645	1.2%
Residential Rate 01	629,860	378		(3,346)	5,035	635,273	0.9%
Commercial Rate M1	713,366	(71)		(3,596)	(37,554)	675,740	-5.3%
Commercial Rate M2	605,387	(2,543)		(3,213)	42,492	645,336	6.6%
Tobacco Rate M1	9,979			-	594	10,573	6.0%
Tobacco Rate M2	1,956			-	2,767	4,723	141.5%
Commercial Rate 01	225,737	1,106		(1,220)	650	227,493	0.8%
Commercial Rate 10	227,264	841		(1,193)	(6,493)	221,612	-2.5%
Industrial Rate M1	58,679	(651)	(235)	(270)	(1,048)	56,744	-3.3%
Industrial Rate M2	345,706	(3,837)	(1,385)	(1,300)	(7,883)	332,601	-3.8%
Industrial Rate 10	38,874	(432)	(156)	(135)	(951)	37,336	-4.0%
Industrial L.I.B, Rate 10	50,130	(556)	(201)	(178)	(1,171)	48,203	-3.8%
Total Throughput Vol.	5,004,929	(320)	(1,977)	(26,294)	13,103	5,015,735	0.2%
Change						10,806	
By Service Class							
Residential	2,727,851	5,823	-	(15,189)	21,700	2,755,374	1.0%
Commercial	1,783,689	(667)	-	(9,222)	2,455	1,785,478	0.1%
Industrial	493,389	(5,477)	(1,977)	(1,883)	(11,052)	474,884	-3.8%

b) Please refer to the 2013 REGN RESULTS 2011 UPDATE Apr_2012 Excel files for the updated regression results.

c) Please refer to the 2013 REGN DATA FILE_Apr 2012 for the updated forecast variable data.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 1, Appendix A, Updated

a) Please confirm that Table 2 includes normalized average consumption by rate and service class that have been normalized to 2013 forecast of heating degree days. If this cannot be confirmed, please provide the South and North heating degree days that the volumes have been normalized to for each year shown.

b) Please provide a separate live Excel spreadsheet that includes all the data used to estimate each of the equations in Tables 5, 6 and 7. Please add actual 2011 data for each of the equations.

c) Please provide the 2011, 2012 and 2013 volume forecast that results from both of the residential equations noted on pages 6 and 7.

Response:

a) The normalized total consumption for the years 2007, 2010 and 2013 presented on Table 2 were estimated using to the 2013 weather normal. The 2013 weather normal is calculated using the 20-year declining trend methodology.

b) Please refer to the 2013 REGN DATA FILE_Apr 2012 excel file at the tabs: Residential Variables, Commercial Variables and GS Industrial Variables.

c) The table shows the total throughput volumes for the forecast scenario that updates for the 2011actuals. The table shows the 2011 actuals and the 2012 to 2013 by service and rate class. All volumes are based on the weather normalized 2013 weather normal.

Total Weather Normalized Throughput Volumes: 10^3 m^3
2011 TO 2013

Line No.	Rate & Service Customer Class	Act. W.N. Total Throughput 2011	Update for 2011 Actuals Scenario: Total Throughput 2012	Update for 2011 Actuals Scenario: Total Throughput 2013
1	Residential Rate M1	2,144,466	2,126,955	2,116,456
2	Residential Rate M2	4,001	3,717	3,645
3	Residential Rate 01	642,479	638,343	635,273
4	Commercial Rate M1	626,357	677,466	675,740
5	Commercial Rate M2	770,529	648,432	645,336
6	Tobacco Rate M1	13,106	10,786	10,573
7	Tobacco Rate M2	5,444	4,723	4,723
8	Commercial Rate 01	232,758	226,786	227,493
9	Commercial Rate 10	245,429	221,344	221,612
10	Industrial Rate M1	56,399	58,175	56,744
11	Industrial Rate M2	333,171	337,976	332,601
12	Industrial Rate 10	47,300	38,413	37,336
13	Industrial L.I.B, Rate 10	39,613	49,155	48,203
14	Total Throughput Volumes	5,161,053	5,042,271	5,015,735
15	Residential	2,790,947	2,769,015	2,755,374
16	Commercial	1,893,624	1,789,537	1,785,478
17	Industrial	476,483	483,719	474,884

Note: weather normalized according to the 2013 20-year trend normal estimate for 2013

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 1, Table 5 &
Exhibit C1, Tab 1, Appendix A, Table 5

a) Please provide a Copy of the Rudden Report Filed in EB-2005-0520.

b) Please provide forecast Weather Normal Values for 2001-2010 and compare to actual.

c) Please provide full details of Independent and Dependent variables, weighting and formulation of the Residential Average Use Regression Equation(s).

d) Compare the formulation to the Enbridge Residential Average use and weather normalized regression / Discuss the differences.

e) Why, apparently, is there no gas price-demand/use relationship? Has this been tested? Discuss.

Response:

a) Please see Attachment 1.

b) The table below compares the actual weather with the annual budget normal estimates for Union's franchise from 2001 to 2010. Please note that seven of the ten years were warmer than normal. Also please refer to the 2013 REGN DATA FILE_Apr 2012 excel file for the southern and northern region historical and normal weather data.

	Weather Actual HDD	Weather Normal HDD	variance	% variance	colder / (warmer)
2001	3,755	4,136	-382	-9%	warmer
2002	3,991	4,115	-124	-3%	warmer
2003	4,278	4,020	257	6%	colder
2004	4,159	4,179	-20	-0.5%	warmer
2005	4,095	4,182	-88	-2%	warmer
2006	3,674	4,177	-504	-12%	warmer
2007	3,997	4,139	-142	-3%	warmer
2008	4,162	4,070	91	2%	colder
2009	4,130	4,034	97	2%	colder
2010	3,796	4,056	-261	-6%	warmer

c) Please refer to the 2013 REGN DATA FILE_Apr 2012 Excel file for the independent and dependent variables.

   Please refer to the 2013 REGN RESULTS 2011 UPDATE_Apr 2012 excel file. Please refer to the four residential tabs regarding use and volume equations for the north and south called: Residential USE Regn North, Residential VOL Regn North, Residential USE Regn South, and Residential VOL Regn South.

   The average use per customer estimates obtained from the use and volume equations are weighted equally.

d) Union's residential demand forecast is based on a forecast methodology that has performed well since 1990 and was reviewed by Rudden and Associates and presented to the Ontario Energy Board in 2006 (EB-2005-0520). The Enbridge method was examined by Union in 2005 and not pursued any further because:

   - The forecast M.A.P.E. error was larger;
   - The vintage demand variable was not significant; and
   - The price variable was not significant.

e) The total bill amount variable in the residential use equation accounts for the gas price-demand relationship. Customers pay the total bill amount; many customers are on monthly equalized budget payment plans. The statistical regression analysis indicates the total bill amount as superior to a strict gas price variable.

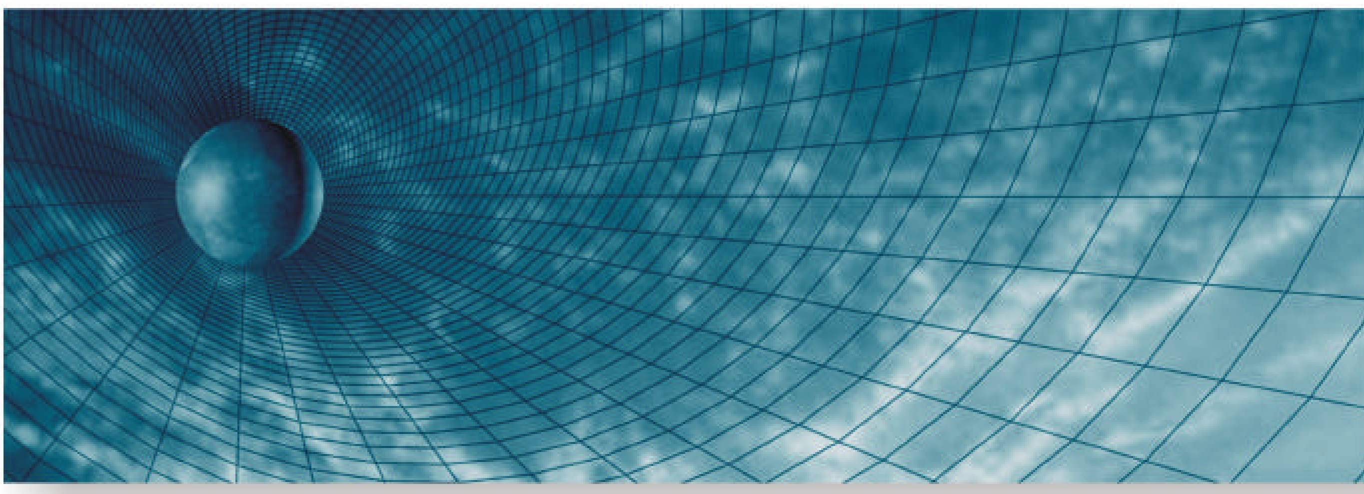
Report to

Union Gas Limited

Regarding

Union Gas Forecast Analysis

December 16, 2004



R·J·Rudden ASSOCIATES

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SECTION I
INTRODUCTION

In August 2004, R.J. Rudden Associates, Inc. ("Rudden") was retained by Union Gas ("Union") to perform an independent, expert evaluation of its forecasting methodology. Union engaged Rudden pursuant to a Directive by the Ontario Energy Board in Union's last rate case (RP 2003-0063). In order to meet the requirements of this project, Rudden assembled a team of professionals with more than forty person-years of gas and electric forecasting experience and industry-recognized expertise in the evaluation and development of such forecasts for electric and gas utilities.

The Principal Investigator for this assignment was George L. Fitzpatrick, a Senior Associate of Rudden and the Principal/CEO of Harbourfront Consulting Group LLC. He is a recognized statistician and econometrician with more than 30 years of experience in developing electric and gas sales and demand forecasts - both econometric and end use; electric and gas weather normalization studies; electric and gas load research programs and analyses; and interfuel competition analyses. He has provided direct and rebuttal expert testimony before many regulatory bodies for more than 30 utility clients throughout the U.S. on subjects such as forecasting, weather normalization, and a variety of comparative economic, statistical and econometric-related analyses. A complete resume for Mr. Fitzpatrick, as well as the other members of Rudden, can be found in Appendix A of this report.

The objective of this project was to evaluate the Union Gas Forecast Models applicable to general service customers from the following perspectives:

- Forecast accuracy
- Logical construction
- Statistical "goodness-of-fit"

Rudden reviewed a variety of documents from Union Gas including the following:

- The May 2004 forecast document entitled, "Union Gas - Demand Forecast Methodology - General Service Markets - Rates M2, 01 & Banner 10" (See Appendix E of this report),
- Information concerning Union's forecast accuracy,
- A summary of the critiques that were made of Union's forecast methodologies by both the OEB and interveners in the last rate case, and
- A complete list of all of the descriptive statistics for all of the models that were in our scope of evaluation.

It should be noted that Rudden's assignment was limited to the review and evaluation of Union's current forecasting practices. While we have made recommendations for Union to consider in future forecast cycles, we were not commissioned to develop new methodologies and forecasts - nor did we see the need to after our review.

SECTION II
FORECASTING ACCURACY

For models designed to forecast in the short term, the best indicator of forecasting success is the accuracy achieved by the forecasting process. The forecasting process refers to both the methodologies employed and the team that has developed those forecasts. Since judgment is an integral part of any forecast, Rudden had to satisfy itself that the team making those judgments was both knowledgeable about the service territory and the factors that affect that service territory.

Since statistical/econometric models are quantitative expressions of the forecasting team's judgment, the best way to evaluate its collective success is to review the accuracy of the forecasts produced over a reasonably representative period of time - in this case, 2001-2003. Before that time, the methodologies employed by Union were of a less complex structure and the specification of the Heating Degree Day (HDD) weather variables, by month, has evolved based on a different set of controlling forecast assumptions (i.e., 30-year Normals have been replaced by a blend of a 30-year Normal combined with a lesser-year declining HDD trend). For example, earlier forecasts did not:

- Include a two-equation approach for the five primary customer rate classes.
- Recognize the impact of past and audited DSM plans.
- Include the impact of future marketing and DSM plans.
- Span 14-year time periods; the early 1990 forecasts were based on 60 months of data.
- Include the retail energy price in most models.
- The energy efficiency variables were not supported by residential and commercial customer survey results.

After evaluating the forecasts of Union Gas over the 1994-2003 periods, Rudden concluded that the most appropriate focus of a forecast accuracy analysis would be the 2001-2003 time period, since it is over this time frame that significant enhancements were made to the Union Gas methodologies and key assumptions about forecast period weather. The following four tables exhibit both the absolute and arithmetic signed "forecast vs. weather normalized actual" percent variances on a year-by-year basis for each of the four primary rate classes. (Both absolute and signed variances are reviewed since Rudden wanted to capture the average yearly error without having positive errors in one year cancel out the negative errors in another). Accuracy is measured by the absolute percent error measurement.

Forecast accuracy for logically constructed short-term models[1] (that is, models with a forecast horizon of up to 12-24 months) is far and away the most important barometer for judging a modeling system's quality. Statistical elegance is less important with these models—performance, as measured by accuracy, is paramount. The reasons for this are threefold:

1. Accuracy of short-term forecast projections are most important to a utility since these forecasts predict near-term revenue adequacy and resource sufficiency for a time period that is critical to the security of energy

[1] ***Short-term models*** for electric and gas utility forecasting are defined by Rudden as having a duration of 1-2 years (i.e., 12-24 months ahead).

supply for customers and adequacy of returns to stakeholders. Clearly, the accuracy of short-term models becomes apparent to both utility and regulator over a time frame in which these results are fresh in everyone's mind. Accuracy comparisons can be made 12 months after a forecast is produced.

This is not the case with long-term forecasts. Long-term forecasts[2] can be predicted as much as 30 years into the future. Further, they are usually updated every year. Thus, there is never a timely debate over long-term forecast accuracy but, rather, a debate over theories, specifications and assumptions.

2. Statistical issues (e.g., autocorrelation, multicollinearity and heteroskedasticity[3]) that could render long-term models unreliable/unstable are less of an issue in a short-term structure. The reason for this is that short-term forecasts progress only a short time distance (in term of time periods ahead) from the end point of the history of the estimated model (in the case of Union's short-term forecasts, the models only predict two months ahead for each calendar month forecasted). Thus, such structural problems, if they do exist, have less of an absolute influence on the forecast results. Autocorrelation, multicollinearity and heteroskedasticity actually increase their influence in a compounding fashion, the longer the forecast horizon. Thus, the shorter the forecast period, the less the overall effect.

3. Further, in monthly model structures, it would be unusual not to have both explainable and unexplainable autocorrelation and multicollinearity since successive monthly observations are usually related and driver variables have a tendency to move together (e.g., it is unlikely that a warmer than normal January will immediately be followed by a colder than normal February). The comparison of the relative accuracy of alternative model structures, when used to backcast the last year of the historical data series, usually provides guidance in selecting the best model structure.

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[2] ***Long-term forecasts*** for electric and gas utilities as defined by Rudden generally have an outlook of between 10-30 years.

[3] ***Autocorrelation*** refers to correlations among adjacent time periods (lag 1 autocorrelation). There may be an autocorrelation for a time lag of one period, another autocorrelation for a time lag of two, and so on. The residuals serve as surrogate values for the error terms. There are several tests for autocorrelated errors. The Box-Pierce test and the Ljung-Box test check whether a sequence of autocorrelations is significantly different from a sequence of zeros; the Durbin-Watson statistic checks for first-order autocorrelations.
Multicollinearity is defined as the presence of correlation among explanatory variables in a regression analysis. This commonly occurs for nonexperimental data. Parameter estimates will lack reliability if there is a high degree of covariation between explanatory variables, and in an extreme case, it will be impossible to obtain estimates for the parameters. Multicollinearity is especially troublesome when there are few observations and small variations in the variables.
Heteroskedasticity refers to nonconstant variances in a series (e.g., differing variability in the error terms over the range of data). Often found when small values of the error terms correspond to small values of the original time series and large error terms correspond to large values. This makes it difficult to obtain good estimates of parameters in econometric models. It also creates problems for tests of statistical significance.

J. Scott Armstrong, "*Principles of Forecasting: A Handbook for Researchers and Practitioners*"
<http://morris.wharton.upenn.edu/forecast/dictionary/defined%20terms.html>(2001)

Component Forecast Accuracy:

The tables found in Appendix B show the forecast accuracy that has been achieved by the Union forecasts. The summary table appears in the text below, and more detailed tables can be found in Appendix B.

The table below sums the results for the four primary rate classes (i.e., Residential M2, Residential 01, Commercial M2, and Commercial 01), representing about 1.2 million customers and 85% of Union's general service rates throughput volumes. It also shows the forecast error for the years 1994 through 2000 and the error for the years 2001 through 2003. The results demonstrate Union's average error for the first seven years and the last three years.

**FORECAST ACCURACY –
TOTAL YEAR VOLUMES - SUM OF THE FOUR PRIMARY RATE CLASSES (10*3 m3)**

Year	Normalized Actual	Forecast	Difference	Actual % Diff.	ABS % Diff.
1994	5,065	5,214	149	2.86%	2.86%
1995	5,022	5,089	67	1.32%	1.32%
1996	5,098	4,911	187	-3.80%	3.80%
1997	5,071	4,784	287	-5.99%	5.99%
1998	4,825	4,802	23	-0.48%	0.48%
1999	4,759	4,960	201	4.05%	4.05%
2000	4,719	4,803	84	1.75%	1.75%
2001	4,554	4,597	43	0.94%	0.94%
2002	4,517	4,426	91	-2.06%	2.06%
2003	4,441	4,406	34	-0.78%	0.78%
			Average from 94-00	-0.04%	2.89%
			Average from 01-03	-0.63%	1.26%

As can be observed from the table above, as well as those found in Appendix B, it is Rudden's conclusion that the forecast accuracy achieved by Union over this 2001 through 2003 time period was quite acceptable and in line with other short-term electric and gas forecasts reviewed by Rudden. ***To contrast, the overall absolute variance from the years 1994 through 2000 was 2.89%. For the years 2001 through 2003, this forecast accuracy improved significantly to 1.26%.***

Finally, a look at the overall total volumes of the Union forecast shows the following for the most recent five-year period (a five-year period has been used due to limitations in the number of years that forecasts were produced on a comparable basis).

FORECAST ACCURACY - TOTAL YEAR VOLUMES - SUM OF ALL RATE CLASSES

Year	Normalized Actual	Forecast	Difference	Real % Diff.	ABS % Diff.
1999	5,499	5,707	208	3.65%	3.65%
2000	5,436	5,569	132	2.38%	2.38%
2001	5,294	5,318	24	0.45%	0.45%
2002	5,276	5,153	123	-2.38%	2.38%
2003	5,183	5,136	47	-0.92%	0.92%
			Average from 99-00	3.01%	3.01%
			Average from 01-03	-0.95%	1.25%

From an accuracy perspective, Union's forecasts have improved over the analysis period shown above. The last three forecast years, which are the result of forecasts with enhanced multi-equational methodologies, have produced more accurate results than earlier years.

In Rudden's judgment, Union's Residential and Commercial Volume Forecast Models (i.e., the forecasts for the four primary rate classes) have historically produced accuracy that is consistent with and in some cases better than other gas utilities whose forecasts have been reviewed by Rudden in the past.

The Industrial Models do not meet that same standard. This is due to the economic vagaries under which Union's general service rate industrial customers operate. That is, their dependence on exports to the U.S. economy and the attendant microeconomic production impacts at the factory floor level, have varying and largely unforeseeable quarter-to-quarter effects on the space and process related natural gas consumption. In addition, the distribution of general service rate industrial customers according to total annual volumes is skewed towards large volume customers. Consequently, industrial NAC is sensitive to the consumption behaviour of these large volume customers.

Union Gas recognizes that the forecast accuracy level for industrial customers is more difficult to achieve that it is for residential and commercial customers. The stand-alone accuracy level for industrial customer volumes is plus or minus four percent.

It may well be that this is the best that can be achieved with a modeling system that does not include a costly segmented, formal and constant customer interview process as part of the methodology.

The general service industrial demand is more difficult to forecast than the comparatively more homogeneous residential and commercial customer. Industrial demand includes both space heating and process-related energy requirements. Both of these energy requirements are affected by factors described below.

The two general service industrial rate classes, rate M2 & 10, that are forecast by the demand volume forecast equation that is under review serve customers that form a small portion of the total industrial sector. These industrial customers are classified as general service by the nature of the size of their natural gas consumption as set by Union Gas rate schedules and not by the nature of their production. Industrial customers can migrate between rate classes, e.g., rate M2 to rate M4 and rate 10 to rate 20 and vice-versa, as their consumption levels change.

The general service industrial customers produce goods for North American and global markets and are affected by economic conditions such as U.S. and Canadian economic growth, foreign currency exchange rates, and global manufacturing competition to name the major factors.

As many of the industrial customers are part of larger corporations, changes in production lines, closures and factory floor expansions and inventory-related production changes are determinants to changes in demand. The distribution of general service customers by annual volume is more skewed to large volume customers in contrast to residential customers, which have a more normal distribution. Changes in the number of large volume customers consequently can have a greater effect on industrial NAC.

These four factors described above combine to make the industrial NAC forecasting activity more challenging. Union Gas recognizes that the demand forecast accuracy for industrial customers is more difficult to achieve than for residential and commercial customers. The accuracy level for industrial customer volumes per se is plus or minus four percent.

SECTION III
FORECASTING PROCESS

Analysis of Forecasting Models

While many forecasting models exhibit statistically significant "goodness-of-fit," it is far more important that forecasting systems start off with a solid logic, supported by economic, technological and/or behavioral theory. Once that foundation is achieved, it is then a matter of selecting available independent variables and statistical constructs that produce a cost-effective, unbiased, and accurate forecasting process. The model's structures and variables employed by Union are consistent with those employed by other utilities that Rudden has evaluated in the past as "best practice" for gas utilities.

Given the fact that Union's forecasting process has the objective of providing accurate results over a one-two year time frame, we believe that proven historical accuracy and solid causal logic override are certain statistical issues that would become far more important if the forecast time frame was long-term. The reason for this opinion is that, systemic equational problems such as multicollinearity, heteroskedascity, and autocorrelation, if they exist in a forecasting model of monthly projections with a 10-year or so historical database, do not have the ability, unless they are dramatic in nature, to have a meaningful, statistically significant effect on a set of short-term forecasting predictions.

To explain, heteroskedastic and autocorrelation disturbances exhibit themselves through either expanding or declining error term amplitudes or discernable patterns in error terms, respectively, associated with successive observations in the historical regression equation observations used to estimate the model. Often times, these estimation problems can be attributable to either a missing variable, co-mingling of causality, or misspecification of an included variable. This non-randomness of the error term may manifest itself in an increasingly expanding effect that may result in the over-or-under forecasting of the dependent variable or certain months of the forecast. Thus, the length of the projection period has a direct bearing on the nature and extent of the heteroskedastic, multicollinearity and autocorrelation effects. In Union's case, each monthly observation is forecast only two steps ahead, thus minimizing any deleterious impact. This reality, coupled with the observed historical forecast performance serves to discount heteroskedasticity, multicollinearity and autocorrelation as important considerations.

Finally, it is clear that the relative accuracy of short-term forecasts becomes evident within a short period of time, thus validating their credibility on a year-to-year basis.

The Rudden team has examined the models used by Union, segmenting our analysis into the following categories:

1. Modeling Approach
2. Variables
3. Regression Results (Descriptive Stats)

1. Modeling Approach

The job of any forecasting group is to produce the most accurate forecasts possible given the resources made available. This is not a matter of statistics or econometrics, per se, but rather one of the allocation of resources within available budgets. In the case of Union Gas, there are a number of forecast components that must be developed every year, each of which requires expert internal resources. The following table shows the relative magnitude of volumes for each class that is subject to the Union forecast process:

UNION GAS RATE CLASSES

	Residential		Commercial			Industrial		Total
	M2	01	M2	01	10	M2	10	
# of Customers	827,198	254,998	77,957	25,375	2,567	5,224	189	1,193,508
% Customers	69.3%	21.4%	6.5%	2.1%	0.2%	0.4%	0.0%	
NAC	2,614	2,734	17,319	9,103	95,713	85,161	276,159	488,803
Total Volumes	2,162,296	697,165	1,350,137	230,992	245,694	444,881	52,194	5,183,359
% Volumes	41.7%	13.5%	26.0%	4.5%	4.7%	8.6%	1.0%	

Union employs a reasonable and commonly used approach to the forecast of customer class usage over a two-year forecast horizon. This approach employs separate models for the forecasting of Use per Customer and the total number of customers. The econometric models incorporate measures of gas price, economic activity, and month-to-month weather explanatory variables (for heating season months). These variables are commonly employed by many gas and electric utilities in the forecast of customers and use per customer, and represent a logical and accepted approach.

The primary drivers of use per customer are traditionally defined as weather, as measured by heating degree-days, gas price elasticity of demand, the positive growth impact of new (or net new) gas appliances, and the negative impact of more efficient appliances/equipment entering the end-use pool. The primary elasticity drivers of these models are short-term in nature and, thus, the models have logically been specified with variables that lean more toward short-term nominal gas price drivers.

Of note is a statement found on page 12 of the Union Gas Demand Forecast Methodology - May 2004 -"For the majority of the 136 demand variables tested that are contained in the eleven demand equations, this 95 percent (Confidence Level of the "t" value of each partial regression coefficient) level is met as 127 demand variables had test scores above the 95 percent confidence level. In nine instances, a lower confidence level was considered …" This acceptance of a lower statistical Confidence Level is quite acceptable if the economic relationship attempted to be captured has sound theoretical basis. Often times, the appropriate economic relationship is not able to be captured with the level of confidence a forecaster would like due to the availability of a data series that would most accurately capture that relationship.

Additionally, all exogenous variables that were employed in these models had the appropriate arithmetic sign, which means that the estimated partial regression coefficient for each independent variable was consistent in the direction of the impact that would be expected under economic theory.

2. Variables

The first issue that was uncovered by Rudden in its analysis revolved around Union's somewhat unconventional, yet well supported, statement that a forecast of gas total throughput volumes should take into account evidence that winter weather in the Union Gas service territory, as measured by heating degree days, has actually exhibited a warming trend over the last thirty or so years. From a practical perspective, the theory of global warming suggests that such a trend is likely, and to include such a theory in a short-term forecast appears reasonable in this case.

Evaluation of the Forecast Methodologies for Residential M2, 01; Commercial M2, 01 and 10 Classes

Union employs a multi-equational approach to the forecasting of the Residential M2 and 01 classes, and the Commercial M2 and 01 & 10 classes. The construct of the volume equations employs commonly used variables such as:

- Number of Customers
- Natural Gas prices
- Weather (as captured in nine separate weather variables identifying the heating months of the year)

This model structure is commonly used to forecast short-term sales by month. The overall statistics of these models are acceptable and the signs of the partial regression coefficients comport with accepted economic theory.

Union takes two additional steps to ensure they capture the appropriate month-to-month distribution of volumes and the noticeable declining trend in use per customer. The first of those steps is to estimate use per customer as a function of the following variables:

- Retail Price of Natural Gas
- Residential Energy Efficiency / or Commercial Segmentation Index
- Weather (as measured by monthly heating degree days)

The Retail Price of Natural Gas Price variable used in the model is specified as a nominal value,[4] as opposed to a real value. A short-term model structure should capture "intensity of use" (i.e., responses to a customer's monthly

[4] ***Nominal value*** *is the actual price experienced by a customer without adjustment for the effects of inflation. Real prices are adjusted for inflation.*

budget) responses rather than longer-term structural changes; therefore, a nominal price variable would be acceptable, and probably preferable, from both a statistical and logical perspective.

The Residential Energy Efficiency Variable and Commercial Segmentation Index have been developed to capture the overall declining trend in use per customer, ostensibly caused by increasing appliance/end-use efficiency. The construct of these variables is based upon surveys of both existing and new residential and commercial customers. While the constructs are different, the overall objective of both is reasonable. The resultant variables add to the explanatory power of the models.

The Weather Variables are specified as a series of monthly variables for the nine heating months of each year. These variables capture both relative monthly use intensities and certain sociological-driven use patterns that go hand-in-hand with the months of the year (e.g., Christmas, New Years, winter school breaks, etc.). The mathematical construct of these variables is one of two major constructs that have been proven to be valuable in predicting monthly gas-use intensity.

Rudden found out that a number of other variables have been tested and Union selected the variables primarily used according to their accuracy, in their forecasting systems. From a practical process perspective, a forecaster must choose a set of independent variables that are logical, measurable and readily obtainable in a time period that meets forecast preparation deadlines. The variables used by Union meet all of these criteria.

While Rudden recognizes that there may be other variables that would perform adequately in the Union forecasting system, we are satisfied with the accuracy that has been achieved by Union, especially over the last three years. Further, the use of multiple equations in the development of the forecasts for five of the rate classes has merit even though each equation includes some of the same variables contained in the other. The reason for this conclusion is that each individual equation has been shown to be less accurate than the average result of both equations. Further, Union has not been successful in finding alternative equations that combine the key demand drivers of the current equations.

Judgmental Adjustments

After the use per customer key demand drivers are developed, there are certain judgmental adjustments that are applied to the NAC forecasts to account for influences that cannot be statistically estimated in the historical series. Those adjustments include:

- Marketing Plan Impacts
- DSM NAC Impact
- Water Heater Standards Efficiency Changes

In Rudden's opinion, judgmental adjustments to a statistically prepared forecast are both appropriate and necessary if the influences being recognized through forecaster judgment are known to exist and are also known not to have existed in the historical data series upon which the models have been estimated.

3. Regression Results (Descriptive Statistics)

Rudden reviewed a comprehensive set of descriptive statistics output for each of the ten residential and commercial models.

As evidenced by the data contained in Appendix C, the models' R-Squares[5], t values of the partial regression coefficients, and Standard Errors are all statistically competent. Further, the arithmetic signs of the independent variables are correct.

As evidenced by the data contained in Appendix D, all of the models have acceptable heteroskedastic disturbances. In the models that do contain autocorrelation, as evidenced by the Durbin Watson d or h statistic, the potential effect of this autocorrelation in the equation is far outweighed by the accurate performance of such models. In multiple regression[6] time series modeling, the presence of autocorrelation and multicollinearity are usually not a question of "if," but "how much." Taking steps to eliminate these time series side effects may have the unwanted result of damaging a model's explanatory and predictive power. In any event, Rudden's view of these issues is that the presence of these side effects is not a serious problem for models that forecast 12-24 months into the future. However, in the interest of completeness, Rudden has included a suggested set of tests for Union to consider in the future forecast cycles.

Valuation of the Methodologies to Forecast Industrial M2 & 10 Classes

Conceptually, the model structure utilized for these classes is commonly used by utilities today. The volume equations developed for these classes include:

- Weather
- Number of Customers
- Lagged Change in GDP
- Price Ratio-Natural Gas to Fuel Oil

The problem is that the resulting forecasts are less accurate than the residential and commercial forecasting efforts. However, the problem is most likely not with the model but with the forecasts of the independent variables used to drive the model. In the case of these customers, their "derived" demand for natural gas varies directly with the demand for their industrial output, and the demand for their industrial output varies depending on national and international forces that are beyond their control.

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5 ***R-Squares***, or the Coefficient of Determination, measures the percent of the variance in the dependent variable that is explained by the independent variable(s).
6 ***Multiple Regression*** is an extension of simple regression analysis that allows for more than one explanatory variable to be included in predicting the value of a forecast variable. For forecasting purposes, multiple regression analysis is often used to develop a causal or explanatory model.

J. Scott Armstrong, "*Principles of Forecasting: A Handbook for Researchers and Practitioners*"
<http://morris.wharton.upenn.edu/forecast/dictionary/defined%20terms.html>(2001)

SECTION IV
OBSERVATIONS ON OEB AND INTERVENOR CONCERNS

In reviewing the concerns of both the OEB and intervenors in Union's last rate case, there were three areas of focus. They were:

1. Statistical Significance vs. Judgment
2. Economic Theory vs. Statistical Estimation
3. Autocorrelation, Multicollinearity and Heteroskedasticity

With these concerns, Rudden offers the following comments for all parties' consideration.

Statistical Significance vs. Judgment

It is Rudden's perspective that every forecast is a mirror of a forecaster's judgment. Regardless of the sophistication of the models employed, it is the forecaster that selects the models, variables and transformations and then makes informed judgments about influences known to exist, but are not modellable for one reason or another. In short-term model structures, there is great value in trying to capture and model "persistence"-- that is, the experience and trends of the recent past. Short-term demand for natural gas for residential and commercial consumers is often best described as changes in intensity of use, usually as a response to weather. Price effects may not be "capturable" with a high degree of statistical accuracy due to the fact that customers have a limited opportunity to respond in meaningful ways (e.g., families need to keep warm and cook meals, and merchants need to open each day for business regardless of how cold it may be). For this reason, time series and pooled structures used to develop long-term forecasts will have more to work with in the development of own price, cross price and income effect elasticities. Critics of the Union forecasts appear to have a focus on statistical "perfection," perhaps at the expense of a good forecast.

Thus, judgment is entirely appropriate under the following circumstances:

- There is a phenomenon that is known to exist by the forecaster that has not been a factor in the historical series (e.g., new technologies, new efficiencies, weather changes, etc.).
- The judgment of the forecaster is experienced, based upon the latest information, and, where applicable, consistent with accepted economic theory.
- The credibility of the forecaster's past efforts is favorable.

Union forecasters meet these tests for appropriateness.

Economic Theory vs. Statistical Estimation

There are instances in which a forecaster knows that there is a certain logical relationship between a dependent and independent variable. As an example, the relationship known as "price elasticity of demand," in Rudden's experience has not been challenged (i.e., a negative arithmetic sign). However, there are times when a forecaster attempts a statistical estimation of this relationship and there are deficiencies in the data or other overshadowing circumstances (e.g., multicollinearity) that will not permit the statistical estimation algorithm to estimate this relationship with a high level of statistical confidence. The fact remains that this relationship is known to exist. If the resultant statistical estimation procedure captures the correct arithmetic sign of the relationship, it is preferable to include the variable in the forecasting model, even though it has a lower confidence "t"value.

Rudden suggests that critics of "t" values of partial regression coefficients below 95% should consider this perspective in weighing the importance of this criticism.

Autocorrelation, Multicollinearity and Heteroskedasticity

In our review of Union's forecasting models, there were instances in which we found evidence of each of these three statistical problems. In our opinion, the impact of these problems on Union's forecasting results were insignificant given the relatively short forecast horizon; and, given Union's accuracy record (see a complete explanation of the reasons for this conclusion on page 5). Any attempt to fix these problems would have to proceed cautiously due to the construct of the models. However, we would like to discuss the practical aspects of these so-called statistical problems in turn:

- Autocorrelation is usually present to some extent in most time series of a monthly construct. Month-to-month observations usually have some serial linkage and this fact can be of value when forecasting one-to-two years into the future.
- Multicollinearity may exist in a relationship estimation structure such as a multiple regression but it does not impede the model's ability to forecast reliably unless the correlated variables make a sudden departure from this collinear relationship in the forecast period—this is not likely in a 1-2 year ahead forecast. We conclude that this concern is without merit in this case.
- Heteroskedasticity can become a problem in a forecast model if the forecast period is sufficiently long enough to allow the non-constancy of a forecast variance to become unstable. In our Recommendations in Section VI, we do offer some ideas for Union to consider in future forecast cycles. However, at this point, given Union's forecast accuracy track record and the length of the forecast period, we do not believe that this represents a significant threat to forecast accuracy.

SECTION V
CONCLUSIONS

Based upon Rudden's review of Union Gas Ltd. Demand Forecast Methodology - General Service Markets - Rates M2, 01 and Commercial M2, 01 & Banner10 - May 10 2003; our analysis of Union's workpapers; our evaluation of forecast accuracy data, as well as discussions with the Union Gas forecasting staff, we conclude the following:

1. In Rudden's opinion, Union's forecasts and underlying methodologies are reasonable and produce accurate results.

2. Union's Volume Forecasts for the Residential M2, 01 and Commercial M2, 01and 10 classes are logical and statistically credible forecasting methodologies that produce accurate results sufficient for reliable12-24-month-ahead projections.

3. Union's Industrial Volume Models are competent and credible as to their logical and statistical construct. However, their accuracy performance is not up to the level of the Residential and Commercial Models. Rudden's scope of work did not envision the development of alternate structures, databases and/or specifications. However, it may well be that these models' accuracy performance is the best that can be obtained for this class due to the nature of industrial customers' gas consumption and the many potential national and international influences that affect their demands for natural gas.

4. For short-term forecasts, such as the ones produced by Union and focused upon in this report, the most important performance parameter that should be considered is the accuracy of the resultant 12-24 months-ahead projections.

5. There are certain judgmental components that have been made by Union forecasters to the subject forecasts. Rudden's position on judgmental forecasts is that it is acceptable and even preferable for qualified forecasting personnel to adjust forecast model outputs under the following circumstances:

   - The phenomenon that is to be captured is known to be influential on current experience and/or future forecasts but there is a lack of historical influence of this phenomenon on the databases that are being used to estimate the econometric forecast model equation(s).
   - The judgmental adjustment should be the product of a structured estimating process that ought to be documented at the outset and reviewed at the time of each forecast update. Additionally, forecasters should continue to test for the statistically significant presence of the phenomenon that is the subject of the judgmental process by including a relevant independent variable that should logically capture that phenomenon when it does become a statistically significant driver in the forecasting model. Once that variable achieves an acceptable "t" value for its partial regression coefficient, with the expected arithmetic sign, then this variable may replace the judgmental adjustment.

SECTION VI
RECOMMENDATIONS FOR FUTURE INVESTIGATION

This section has been developed to offer Union's forecasting team some ideas that may prove to be cost effective if tested in future forecasting efforts. However, Rudden offers these caveats:

- Union has in place a competent forecasting process yielding accurate results. If Union judges that these recommendations are worthy of consideration, then we suggest that Union start with the first recommendation and, after testing, proceed to the second, and so on. However, it is conceivable that the first recommendation may be the only one necessary to test, since it may serve to improve model performance and reduce statistical side effects to a degree that would make further testing unnecessary at this time.

- While Rudden believes that the following recommendations will improve the statistical sophistication of the model, we do not know whether they will provide any marginal benefit in terms of additional accuracy for the additional cost. Union's first consideration should be to preserve the accurate performance of its forecasts.

Given the caveats mentioned above, Rudden recommends the following for Union's consideration:

Respecification of Weather Variables

Currently, Union's weather variables, by virtue of their specification, capture the **average** effect of heating degree-days over the historical data series. If the weather sensitivity of the monthly use per customer were effectively a constant that varied year-to-year around some average, then the Company's current specification would be optimal. However, it is conceivable that the current specification, by virtue of the fact that use per customer seems to be declining over the historical model estimation period, may be overstating the monthly correction in the forecast year. Further, this error could be compounded when Union normalizes NAC to assess forecast accuracy using the partial regression coefficients from each model.

A potential remedy for this potentially suboptimal specification would be to normalize each historical month in the model database, using a monthly regression analysis of the form (U/C=a+/- b*(monthly HDD) +/- c*(monthly trend variable) for each calendar month group of observations. Then the monthly-normalized equation output could be included in the forecast model to more accurately capture declining weather sensitivity.

When forecasting for the test year and beyond, Union's monthly forecasts would already contain the latest weather sensitivity coefficients as a result of the pre-normalization process and the efficiency trend phenomenon may be more identifiable from a statistical perspective.

An additional benefit may be the fact that, since model variance would be decreased; there may be a better chance of higher "t" values of the partial regression coefficients for the nominal price, customer and efficiency variables.

Testing of ARIMA Model Structures

As a check on the currently employed model structures, Union may want to consider employing an ARIMA-type[7] structure on the individual-month normalized U/C data by class. The Rudden team has had success utilizing, for example, Box Jenkins Model[8] and Box Jenkins Transfer Function models[9] for the purpose of forecasting 12-24 "steps ahead."

An alternate suggestion would be to consider the use of a tool such as Dynamic Regression that has the capability of identifying annual, monthly, or seasonal trends, and accounting for those trends. Perhaps, a coupling of this tool with a linear or polynomial trend parameter to capture the conservation effect would give Union a more powerful single equation perspective and reduce the need for averaging of two forecast equation results.

Alternatives for Minimizing Autocorrelation and Heteroskedasticity

In reviewing the descriptive statistical outputs for the ten residential and commercial models, the early years of the historical series tended to fit the data better than the later years. In other words, the scatter of the residual plots widened at the end of the historical series. Rudden recommends that Union consider testing in future forecast efforts:

1. Shorten the historical data series upon which the models are based. This may help remove the potentially less relevant data in favor of focusing on the most recent history.

2. Experiment with weighted regression. This would allow Union to keep the same data series but add emphasis to the latter year observations.

In those models that exhibit significant Durbin Watson[10] test results, Rudden recommends:

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[7] ***ARIMA*** (Auto Regressive Integrated Moving Average model.) A broad class of time-series models that, when stationarity has been achieved by differencing, follows an ARMA model. An ARMA model is a type of time-series forecasting model that can be autoregressive, moving average, or a combination of the two. In an ARMA model, the series to be forecast is expressed as a function of previous values of the series (autoregressive terms), and previous error terms (the moving average terms).

[8] ***Box Jenkins Model*** is a form of autoregressive-integrated-moving average (ARIMA) models for time series forecasting problems. Originally developed in the 1930s, the approach was not widely known until Box and Jenkins (1970) published a detailed description. For more information see: Box, G. E. P. & G. M. Jenkins (1970), Time-Series Analysis. San Francisco: Holden-Day. Later editions were published in 1976 and 1994, the latter with G.C. Reinsell. Mentzer, J. T. & K. B. Kahn (1995), "Forecasting technique familiarity, satisfaction, usage, and application" Journal of Forecasting, 14, 465-476.

[9] ***Box Jenkins Transfer Function Model*** is a model that employs other independent variables other than time as drivers in an ARIMA model framework.

[10] ***Durbin Watson*** is a measure that tests for autocorrelation between error terms at time t and those at t + 1. Values of this statistic range from 0 to 4. If no autocorrelation is present, the expected value is 2. Small values (less than 2, approaching 0) indicate positive autocorrelation; larger values (greater than 2, approaching 4) indicate negative autocorrelation. Is autocorrelation important to forecasting? It can tell you when to be suspicious of tests of statistical significance, and this is important when dealing with small samples. However, it is difficult to find empirical evidence showing that knowledge of the

1. Experiment with a Cochrane Orcutt –type model structure. We have found the models to be effective at capturing periodicity that may not be captured by the monthly HDD variables.

2. Review the practicality of transformations and elimination of lagged dependent variables, so long as they do not interfere with accuracy objectives.

In sum, Rudden makes the recommendations in recognition of the reality that all forecasting processes are in constant need of review and upgrade, when and where they make sense. However, Union forecasters should first and foremost ensure that any suggestion contained in this report, or from any other source, does not conflict with the accuracy that Union is currently achieving. The goal of statistical perfection must come second to accuracy projections in a short-term forecasting environment.

Durbin-Watson statistic leads to accurate forecasts or to well- calibrated prediction intervals. Do not use it for cross-sectional data as they have no natural order.

J. Scott Armstrong, "*Principles of Forecasting: A Handbook for Researchers and Practitioners*" *<http://morris.wharton.upenn.edu/forecast/dictionary/defined%20terms.html>(2001)*

APPENDIX A
PROFESSIONAL RESOURCES

GEORGE L. FITZPATRICK

George L. Fitzpatrick is the Managing Principal/CEO of Harbourfront Consulting Group LLC. His professional experience includes eight years of service at Long Island Lighting Company managing the Load Research, Forecasting, and Cost of Service Divisions. After that, he held the position of Vice President of Demand Planning with Stone and Webster Management Consultants, Inc.

Twenty-two years of his career have been spent with Applied Energy Group, Inc. as its founder, CEO and Managing Principal. Over his tenure as CEO, he built the firm from one consultant to over twenty-five employees. In 2002, he reached an agreement to sell his share of the firm in order to pursue consulting and expert witness assignments that were specific to his experience, expertise and past utility client relationships.

In 2002, Mr. Fitzpatrick formed Harbourfront Consulting Group LLC to focus on the provision of expert witness services and litigation support in areas that have been central to Mr. Fitzpatrick's practice over his career. More information about the firm and its professional resources can be found at www.harbourfrontllc.com.

Mr. Fitzpatrick has provided expert direct and rebuttal testimony before federal and state regulatory bodies and judicial authorities on subjects such as:

- Lifecycle Economic Evaluation of Utility Investments
- Econometric/statistically-based Load and Energy Forecasting
- Weather Normalization Studies of both gas and electric test year sales
- Weather Normalization probabilistic correction of System Peaks and Class components
- Strategic Planning
- Comparative Economics of Electric Generation Investments
- Load Research Program Sample Design, Implementation and Analysis
- Nuclear and Fossil Power Plant Cost and Performance analyses
- Econometric and Statistical Studies on Utility- related Issues
- Rate Design
- Cost of Service Studies
- DSM/ Renewable Program Evaluation
- Performance Standard design and statistical construction
- SAIDI / SAIFI-related statistical investigations
- Rebuttal testimony on a wide range of statistical and econometric-related subjects.

Over Mr. Fitzpatrick's consulting career he has provided services to over 50 electric and gas utility clients both in the U.S. and abroad. However, there are a number of clients that have utilized his services on an ongoing basis over the years as a senior management consultant and/or expert witness. These clients include:

- Arizona Public Service Company (Pinnacle West)
- Bermuda Electric Light Company Limited
- Consolidated Edison Company of New York
- El Paso Electric Company
- Entergy
- Freeport Electric
- Georgia Power Company (Southern Company)
- KeySpan Energy
- New England Electric System
- Niagara Mohawk Power Corp. (National Grid)
- New York Power Authority
- Northeast Utilities
- TXU Electric (TXU)
- Westar Energy (and its three predecessor companies)

Over his 24 year professional consulting career, he has also served his client base as a negotiator, often playing a key role in the negotiation of multi-million dollar, short and long term utility power supply and franchise contracts (e.g., Ft Bliss, White Sands Missile Range, University of Texas, and El Paso Water Utilities and El Paso Electric Vs. the City of Las Cruces).

Mr. Fitzpatrick has a Master of Business Administration degree in Economic Theory and a Bachelor of Arts in Economics, both from St. John's University. He has also completed course work toward a Master of Science degree in Management Engineering from Long Island University (C.W. Post) as well as advanced training in Box Jenkins forecasting techniques and econometric and statistical modeling. He possesses a Certificate of Mastery in Reengineering from the Hammer Institute and is a member of the Association of Energy Engineers (AEE) and the Energy Services Marketing Society.

PROFESSIONAL EMPLOYMENT

2003-Present	Harbourfront Consulting Group, LLC *Managing Principal and CEO*

Founded Harbourfront in 2002. HFG's focus is the development of strategies, analyses and expert testimony to assist its primarily investor-owned utility client base in objectively and expertly presenting and defending issues central to the client's corporate mission. Primary areas of the practice are electric and gas forecast development and review; engineering economic studies; comparative economic studies; lifecycle economic studies; statistical and econometric analyses and rebuttal; rate design and cost of service studies; performance standard statistical design and rebuttal; distribution reliability-related analyses and utility accounting-related matters.

1982 - 2003	Applied Energy Group, Inc. *Founder, President & CEO*

Founded AEG in 1982. The focus of this consulting practice centered in the areas of Peak Load and Energy Forecasting, Load Research program sample design, implementation and analysis, Demand Side Management Program Evaluation, Electric and Gas Weather Normalization Studies, Nuclear and Fossil Generation Cost and Performance Studies and Comparative Engineering Economic Studies of Utility Generation and other investments. Mr. Fitzpatrick provided expert testimony on the above-mentioned areas and also provided clients with leadership services in the startup of new diversification ventures.

1979 - 1981 Stone & Webster Management Consultants, Inc.
Vice President—Demand Planning

Responsible for the coordination and direction of consulting activities in the Planning, Load Research, Load Forecasting, and Load Management areas within the corporation. Additional responsibilities included analysis of data processing requirements and potential new markets for consulting activities - a diversification from Stone & Webster's traditional lines of business.

1971 - 1979 Long Island Lighting Company
Manager—Load Research, Costing and Forecast Division

Primary responsibilities centered on Electric Peak and Energy Forecasts; Electric and Gas Weather Normalization; Statistical Sample Design Development; Load Research Study Implementation; Load Data Management and Analysis; Long Island Lighting Company's Annual Population Survey; all Long-Range Demographic Projections; the collection, processing, and overall supervision of the billing of customers under the Long Island Lighting Company's commercial/industrial time-of-use rate, the Electric Class of Customer Annual System Load Research Study; and all statistical and econometric- based studies performed by Long Island Lighting Company's Economic Research Department.

In 1978, responsibilities were expanded to include fully allocated and marginal cost-of-service studies for electric and gas and total factor productivity studies.

PROFESSIONAL EXPERIENCE

Expert Testimony and Regulatory Support (Selected Assignments)

El Paso Electric vs. City of Las Cruces, New Mexico-2000 Federal Court-Ordered Mediation:
Participated as part of El Paso Electric's officer/attorney team in the final court-ordered mediation sessions that resulted in the settlement of the 10-year dispute between the two parties. Prior to this mediation, worked on behalf of the Company to negotiate a settlement with the City's consultants. .

Freeport Electric-1995 Docket No. 95-E-0676, 2001 Docket No. 01-E0965, 2003Docket No. 03-E-0686:
Provided direct testimony supporting Freeport's KWH sales and peak demand forecasts in four NYPSC proceedings. Constructed econometric models based forecast methodology by calls along with weather

normalization of the test year sales. Provided testimony on the selection of Freeport-specific DSM programs to meet Commission requirements.

Indian Point 2 and Indian Point 3 / Consolidated Edison Company of New York, Inc. and New York Power Authority - NRC Docket Nos. 50-247-SP and 50-286-SP:
Prepared rebuttal testimony comparing the economics of early retirement of the Indian Point units vs. potential conservation investment alternatives in New York State.

KeySpan Energy-1998 Docket Nos. ER98-11-000 and EL98-22-000, 2003; Docket Nos. ER04-112-000 and ER04-112-001:
Provided expert testimony before FERC on the appropriate segmentation of fossil generating plant fixed and variable O&M Costs. Developed statistical models, by plant, to support this segmentation. Testimony was updated again in 2003 for the FERC Docket related to the renewal of the contract that was originally brought before FERC in 1998.

Oklahoma Natural Gas Company- 1991 PUD Docket No 001017:
Provided rebuttal testimony on the comparative economics and efficiency of electric and gas DSM programs and made recommendation to the Oklahoma Commission on incentive rate making for DSM-related investments.

Palo Verde 1, 2, & 3 / Arizona Public Service Company-Docket Nos. U-1345-85-156 and U-1345-85-367:
Provided direct testimony presenting comparative economic analysis of Palo Verde vs. hypothetical coal unit alternative. Provided econometrically developed estimates of Operation and Maintenance Costs, as well as Capital Additions Costs. Provided independent statistically derived estimates of lifecycle Capacity Factors for the Palo Verde units. Participated in the training of APS witnesses.

Palo Verde 1 & 2 / El Paso Electric Company / Texas - Docket No. 7460:
Provided direct testimony on lifecycle economics of nuclear vs. coal alternative. Provided direct testimony on decisional prudency of company to enter into nuclear investment. Provided load forecast of company's future energy and peak demand needs. Participated in the training of Company witnesses.

Palo Verde 1, 2, & 3 / El Paso Electric Company Docket Nos. 8892, 9069 and 9165:
Provided Direct Testimony presenting comprehensive industry analysis and statistical analysis of Nuclear Performance Standards. Presented statistically derived optimal Performance Standard for Palo Verde Units 1, 2, and 3. Provided Rebuttal Testimony discussing theoretical and statistical flaws in intervenor's Performance Standard proposal.

Plant Hatch and Plant Vogtle / Georgia Power Company / Georgia - Docket Nos. 3554-U and 3673-U:
For the Vogtle Financing Case, the Vogtle Rate Case and the Hatch Rate Case: Provided rebuttal testimony on comparative economics of Plant Vogtle, provided rebuttal testimony (with presentation to Commission) on Vogtle's economics, and statistically derived projections of Vogtle's performance and Hatch O&M Costs, participated in witness training, and developed internal statistically-based O&M and Capital Additions "Targets" for Plant Hatch and Plant Vogtle.

Plant Hatch and Plant Vogtle / Georgia Power Company - Docket No. 3840-U:
Provided Rebuttal Testimony that pointed out methodological and statistical flaws in Staff consultant's Performance Standard proposal. Presented parameters for a statistically unbiased, optimal Performance Standard.

Shoreham / Long Island Lighting Company / New York-Docket No. 28252:
Provided rebuttal testimony on most likely performance of Shoreham Unit. Provided testimony on most likely Operation and Maintenance Cost levels and Capital Additions Cost level for Shoreham based upon econometric analysis of nuclear industry. Provided testimony on demand-side vs. supply-side alternatives for the Long Island Lighting Company.

Western Resources-2001 KCC Docket No. 1-WSRE-436-RTS:
Provided direct testimony and supporting statistical / engineering economic analyses on the prudence of Western's investment in the Stateline Generating Plant. Also provided direct testimony on the statistical weather normalization of test year sales.

Developed comparative economic analysis on the benefits to Westar and remaining customers of special power supply contracts for Large C&I customers.

Western Resources – 1996 KCC Docket Nos.193, 305 and 193,30; -U96-KG&E-100-RTS:
Developed an accelerated depreciation plan for Wolf Creek Nuclear Unit to reduce cost of production to market-based competitive levels by 2000 - 2005.

Western Resources – 1996 KCC Docket No. 193,307-U96-WSRE-101-DRS:
Provided expert testimony and supporting statistical analysis for test year, class weather normalization, as well as, primary and secondary economic benefits of key customer discounted contracts.

Western Resources - Missouri Testimony in Generic Proceeding (1994:)
Provide expert testimony during the Missouri Public Service Commission's rule making proceeding concerning Integrated Resource Planning. The testimony discussed the consideration of alternative fuel sources as an end-use measure when developing their resource plan. (MPSC Docket)

Wolf Creek / Kansas Gas and Electric Company / Kansas City Power and Light Company/Kansas-1984 Docket Nos. 84-KG&E-197-R-142, O98-U / Missouri Docket #ER-85-128, EO-85-185:
Provided rebuttal testimony on lifecycle economics of nuclear vs. coal alternative. Provided first-year and lifecycle statistically based estimates of Wolf Creek's Operation and Maintenance Costs and Capital Additions Costs. Provided first-year and lifecycle estimates of Wolf Creek's Capacity Factors. Participated in the preparation of KG&E witnesses on the subjects of statistics, econometrics, forecasting, and engineering economics.

Atlanta Gas Light – Georgia (1997):
Worked with senior management to develop testimony for a performance based rate plan in support of the unbundling of gas service.

El Paso Electric Company -Texas (1997-1998):
Developed unbundling strategy and performance based rate plan in support of ongoing Texas PUC workshops on the unbundling of electric service.

Empire District - Missouri (1992):
Provided econometric rebuttal testimony critiquing MPSC Staff's direct testimony on Empire District's forecast. Staff accepted rebuttal testimony and the Company's forecast was accepted for use in the rate case.

Minnegasco - Docket No. G-008/GR-92-400 (1993 - 1994):
Developed a set of econometrically derived, short run forecasts for Minnegasco's major customer classes. Provided direct expert testimony regarding the use of these forecasts as a factor in determining the need for and magnitude of Minnegasco's requested rate increase. Assisted in preparation of cross-examination of intervening parties. On rebuttal, supported the implementation of weather normalization adjustments and discussed the effects of an adjustment on varying classes of customer use. All testimony was accepted by Staff.

Missouri Public Service (MOPUB) - (1992):
Provided econometric-based rebuttal testimony critiquing MPSC Staff's direct case criticizing MOPUB's forecast. Rebuttal testimony resulted in Staff stipulating to the use of the Company's forecast.

Palo Verde / Arizona Nuclear Power Project:
Developed computer software to facilitate budget tracking and comparison. Developed econometric-based target estimation models of Operation and Maintenance Costs. Developed target estimation of Capital Additions Costs based upon econometric modeling. Developed forced and planned outage statistical models to be used in regulatory proceedings for all participants as well as for internal outage planning. Acted as Advisor to Palo Verde Participant's Engineering and Operating Committee on Palo Verde Cost and Performance budget targeting.

Iowa Power Company:
Preparation of a generic proceeding-related evaluation of Iowa Power Company's current and planned DSM activities in light of its specific planning related need for DSM resources.

Long Island Lighting Company :(1974-1979)
Testified as an expert witness, usually in both the direct and rebuttal phases, in the following New York State Public Service Commission proceedings: Docket Numbers:

- 26733
- 26829
- 26985
- 27136
- 27154
- 80003
- 27319
- 27374
- 27375
- 28223
- 28252

on subjects such as econometric and econometric-end use Electric and Gas Peak and Energy Forecasts, Load Research studies for cost-of-service analysis, Load Management, Cogeneration, Conservation and statistical studies for weather normalization of gas send out and electric energy requirements data.

SELECTED CONSULTING ASSIGNMENTS

El Paso Electric Company
Developed a business plan for and then implemented an Energy Services Business Unit (ESBU) that had as its mission key customer retention contracting and the provision of value added products and services in the areas of energy efficiency, power quality, standby generation, and "behind the fence" maintenance and support services.

Bermuda Electric Light Company, Ltd.
Consulted senior management on opportunities for diversification and franchise protection; from 1993 through 1997. Businesses developed include a full service ESCO (BESCO) and Power Protection Leasing Programs for Residential and Commercial customers.

Western Resources
In 1995, was retained by Western Resources to provide expert advisory services and supporting research to assist in the development of a non-traditional Energy Service Company (ESCO). This engagement also involved the analysis of profitability of certain customer classes.

WPI Group International
In 1993 through 1994, provided advisory services for the acquisition of MICROPALM by WPI. After acquisition, provided strategic market and product planning advisory services to the CEO.

Delmarva Power & Light Company (DP&L)
From 1994 to 1998, supported a market research and business plan development project for the development of a dispatchable photovoltaic power supply system business. Based on our initial contribution, DP&L turned over the entirety of the Phase II commercialization to my firm.

Richardson & Associates
Since 1982, has provided expert technical, economic and business plan analysis for over 15 energy-related venture capital business opportunities. This consulting relationship is ongoing.

Applied Energy Technologies Corporation (AET)
Led the formation of a jointly held subsidiary with Delmarva Power & Light Company, A.C. Battery Corporation (a subsidiary of General Motors) to advance both grid-connected and non-grid-connected dispatchable photovoltaics to domestic and international commercialization. Other contributors include the U.S. Department of Energy, Solarex Corporation (a division of Amoco/Enron), and Ascension Technologies

NCR Corporation
In 1981 through 1983, was retained by NCR to develop a diversification business in the automatic meter-reading field. Developed business plans, marketing plans, and product functional specifications. Worked with NCR's CEO and senior management team.

Confidential Diversification Studies and Business Planning Engagements
Senior Management advisory services, development of business plans, and diversification strategies for twelve nationally known organizations. Since these assignments are governed by strict confidentiality agreements, they cannot be publicly identified.

Planning & Forecasting (Selected Projects)

New York State Electric & Gas Corporation (NYSEG) - (1994 -1997)
Served as Responsible Officer for AEG's development of a Multi-Equational Small Area Forecast Modeling System. This system is used to track monthly sales geographically in the NYSEG system, identifying significant weather normalized monthly variances almost in "real time" so that NYSEG can recognize and react to significant changes in a shorter elapsed time.

Western Resources/Westar - (1984 - 2004)
Provide continuing advisory services to Western Resources (now Westar) on potential methodological upgrades to their forecast and weather normalization methodologies.

Long Island Lighting Company (LILCO)
Directed the preparation of LILCO's Annual Long Range Peak and Energy Forecasts during the years 1974 - 1979. Constructed the first Engineering End Use and Econometric End Use models for electric forecasting in New York State; utilized Box-Jenkins stochastic and multiple transfer functions for short run electric forecasts; employed two and three stage regression techniques in SIC-based commercial-industrial forecasting.

In 1994, provided advisory services to review adequacy of the econometric methodologies for the capture of "market transformation" DSM and efficiency effects.

Saudi Arabia – 1995
Selected from an international list of experts to perform a comprehensive review of Saudi Arabia's largest utility's overall planning and forecasting procedures, methodologies, and results. This two-phase project also called for the reengineering of these processes once the analytical and fact-finding phase was complete.

Bermuda Electric Light Company, Ltd. (BELCO) - (1994)
Reviewed BELCO's existing forecasting process and provided a "phase in" solution for enhancing their forecasting systems.

Freeport Light & Power - (1995-2004)
Have and continue to prepare Freeport’s short and long-term electric peak and energy forecasts. Have presented and defended Freeport’s forecasts and weather normalization studies in its last three rate cases.

INNOVATIVE MARKET SEGMENTATION & PROFITABILITY STUDIES

Western Resources
Served as Responsible Officer for a Competitive Assessment of Western Resources key customer's responses to cost competition.

CINergy
In 1995, advisor to senior staff in a multi-phase project that had as its objective the meaningful (from a risk-profit perspective) segmentation of CINergy key customer markets and the analysis of profitability of the segments. This was followed by the development of strategies to optimize the use of CINergy's marketing resources to maximize shareholder returns while ensuring the long-term viability of the company.

Demand-Side Management Program Design, Reengineering, & Evaluation

Bermuda Electric Light Company, Ltd.
Directed a multi-faceted evaluation of the potential for DSM on Bermuda. Conducted in-depth research of various customer classes to determine likelihood of adoption of available DSM technologies. Building on this research, developed a series of pilot programs that were implemented in 1993, as well as evaluation strategies to be employed at the programs' conclusion.

Consolidated Edison Company of New York, Inc.
Project Manager for a Conservation Assessment Study which included designing a methodology and performing analysis to impact Conservation measures in the residential and commercial sectors to meet requirements imposed by New York PSC in Case No. 28223.

Long Island Lighting Company (LILCO)
Directed a research project focusing on the right-sizing of LILCO's DSM program in the face of a maturing market condition, as well as on the measurement of the extent to which LILCO's programs have successfully moved the market to energy efficient technologies. Research includes an assessment of the impacts of pure market forces on DSM and the role of rebates and information in overall market capture for DSM technologies.

Project Manager for LILCO's 1992 Research and Development Initiative entitled, "Institutional Barriers to Conservation in Master-Metered, Tenant-Occupied Commercial Office Space." The project involved determining the market conservation potential, identifying institutional barriers through focus groups and interviews with landlords and tenants, and establishing a pilot program and blueprint lease to implement in order to enhance DSM measures in the relevant market.

Directed the comprehensive evaluation of LILCO's 1987 Conservation and Load Management Programs. This evaluation is contained in a three-volume report, which has been called the "most comprehensive" effort to date in this area.

Directed the evaluation of LILCO's 1988 and 1989 Conservation and Load Management Programs. Directed the preparation of a June 1988 Load Management Study. Specific responsibilities included estimating Load Management reductions included in LILCO's Load Forecasts by major components.

Minnegasco
Served as the Senior Management Advisor to Minnegasco's DSM/Load Research Program from 1993 through mid-1995. Responsibilities included contract negotiations with consultants, supervision of consultant's activities, and resolution of technical issues, and on-site presence as required to effectively oversee all Load Research-related activities.

New York Power Authority (NYPA)
Served as the Senior Management Advisor for NYPA's $120 million High Efficiency Lighting Program (HELP) having primary responsibility for drafting and negotiating DSM cost sharing umbrella contracts with New York State and New York City.

Analysis on behalf of NYPA of Energy Systems Research Group's (ESRG) Conservation Assessment Report submitted in FERC Case No. 2729: Prattsville Pumped Storage Facility.

Supervised the development of an evaluation of potential Load Management strategies for the NYPA's municipal customers, including a cost/benefit analysis and specific Load Management test programs.

Named "Advisor" to NYPA's extensive Conservation Ten-Year Program.

New York Power Pool
Analyzed the conservation forecasts contained within the Member Systems' individual long range forecasts and critiqued intervenors' conservation forecasts and analyses.

New York State Electric & Gas Corporation (NYSEG)
Served as Responsible Officer for NYSEG's 1991 & 1992 Commercial / Industrial Process and Impact Evaluations. Served as Responsible Officer in the development of NYSEG's June 1994 DSM Market Transformation Study.

Orange and Rockland Utilities (O&R)
Assessed the potential for and designed an Energy Cooperative Program for O&R's commercial customers. Directed project to assess new regulated and unregulated business opportunities to diversify O&R from its core business.

Rochester Gas & Electric Corporation
Served as Responsible Officer for RG&E's 1990-94 DSM Evaluations. Represented RG&E in all DSM-related interactions with PSC Staff.

Load Research

Electric Power Research Institute (EPRI)
Advisor to EPRI's Demand Program. Author of RP 1588-3 "Load Data Management and Analysis"; co-author of EPRI Rate Design Study Topic Paper 3: "Issues in Load Research."

Elizabethtown Gas Company
Asked by Senior Management to assess Elizabethtown's Load Research Program and develop a set of recommendations that would result in full cost-effective utilization of the Load Research resource, developed study plan, conducted in-depth technical interviews of potential load research clients, and presented findings and recommendations to all levels of Management.

Iowa Power Company
Directed weather normalization analysis on historical system peak demands. Results from analysis will be utilized in future system peak demand forecasts.

Long Island Lighting Company (LILCO)
Designed and implemented stratified sampling software that employed Dalenius-Hodges and Neyman Allocation techniques with stratum optimization and validation. Also directed LILCO's Load Research Program.

New England Power Service Company (NEPSCo)
Reviewed NEPSCo's Load Research Data Management and Analysis System from analytical and data perspectives and developed a NEPSCo-specific computer hardware and software plan for implementation.

New York Power Authority
Directed the review of the existing Load Research Program and formulated a Management Plan to specify future needs in the areas of sample design, hardware, software, and staffing.

Assisted in the development of specifications for a microcomputer-based Load Research Data Collection, Editing and Analysis System.

New York State Electric & Gas Corporation (NYSEG)
Served as Technical Advisor to the Manager of NYSEG's Load Research Department.

Northeast Utilities Service Company
Performed a comprehensive audit of the technical, software, and organizational aspects of the Northeast Utilities Load Research Program, including the identification of current uses and recommended future cost-effective uses within the company.

Supervised development of a study to analyze load research, weather, and attribute data for the small Commercial and Industrial customer group.

Northern States Power Company (NSP)
Directed the review of all aspects of NSP's load research process and presented findings in a comprehensive presentation to senior management.

Pacific Gas & Electric Company (PG&E)
Performed a comprehensive audit of the PG&E Load Research Data Management and Analysis System. Also, assessed the value of Load Research to all relevant departments in the company including recommendations for more cost-effective uses of Load Research data for both current and future applications.

Tennessee Valley Authority (TVA)
Conducted review of TVA's Sampling Plan strategies and methodologies.

DSM Bidding

Orange and Rockland Utilities
Directed the economic evaluation of the first utility bidding program in New York State.

Cogeneration

Caribbean Gulf Refining Corporation
Performed an economic review for the construction of a nine megawatt Cogeneration facility.

Day and Zimmermann, Inc.
Performed a detailed analysis on the potential for Cogeneration Systems in the United States, which included the development of a comprehensive marketing strategy.

Orange and Rockland Utilities
Developed a Corporate Strategy for Cogeneration in the O&R service territory.

PUBLICATIONS, PRESENTATIONS, AND SEMINARS

Speaker, “The Electrotechnologies Conference,” El Paso Electric Company; El Paso, Texas; March 31, 1998.

Speaker, “The Customer Information Seminar,” El Paso Electric Company; El Paso, Texas; October 7, 1997.

Speaker, “The Energy Revolution Conference,” El Paso Electric Company; UTEP Campus; El Paso, Texas; June 3, 1997.

Speaker, “Customer/Market Segmentation to Optimize Competitive Opportunities,” AMRA 1996 Annual Symposium; New Orleans, Louisiana; September 10, 1996.

Speaker, “Customer Segmentation,” Infocast; Deloitte & Touche; Strategic Marketing Seminar; Atlanta, Georgia; May 1996.

Speaker, "Reengineering Customer Service & DSM - Keys to Building Competitive Advantage in the Future" with Steven J. Maslak; CARILEC CEO Conference; Freeport, Bahamas; June 1 & 2, 1995.

Speaker, "A Presentation To The Deloitte & Touche Partners" with Steven J. Maslak; Public Utilities SLIP Meeting; Las Vegas, Nevada; December 12-13, 1994.

Speaker, "Demand Side Management Alternatives for the Caribbean," Caribbean High-Level Workshop on Renewable Energy Technologies; December 5-9, 1994.

Speaker, "Projects For Energy Efficiency, And The Conservation Of Economic And Environmental Resources," The Caribbean Workshop On Renewable Energy Technologies; St. Lucia, West Indies; December 5-8, 1994.

Speaker, "Demand Side Management As An Economic Development Tool," MEUA Conference; Syracuse, New York; October 13, 1994.

Speaker, "The Effect Of The Market Transformation Phenomenon On DSM And Utility Competitiveness," EUMMOT Fall 1994 Meeting; Corpus Christi, Texas; September 9, 1994.

Speaker, "Evaluation Protocols: Preparing For DSM Evaluation," Presentation to the 4th Quarter EUMMOT Meeting; Columbia Lakes, Texas; December 13, 1993.
Author, "Incentive Regulation in the United States: an Update," EEI; 1992.

Speaker, "The Career Challenges Facing the Electric Industries in the 1990's," Hofstra University, M.B.A. Career Forum; Hempstead, New York; April 1992.

Speaker, "DSM Evaluation for Incentives: How Heavy Should the Burden of Proof Be?" Washington Gas Least-Cost Planning Conference; Washington D.C.; April 1992.
Speaker, "Practical Cases in Evaluating Energy Efficiency Initiatives," Hydro-Quebec Symposium; Montreal, Canada; November 1992.
Author, "Integration of Load Research into the DSM Evaluation Framework," Chapter 8; DOE DSM Evaluation Handbook.

Speaker, "Measuring the Impacts of Demand Side Management Programs," Northern States Power DSM Evaluation Overview; Minneapolis, Minnesota; December 1991.

Speaker, "Incentive Regulation an Overview of Operating Incentive Programs in the U.S. Today," The Southeastern Electric & Gas Conference; University of Georgia; Atlanta, Georgia; August 1991.

Speaker, "The Comparative Costs of and Sensitivities Surrounding the ALWR vs. Alternate Generation Options," EEI Working Group; Washington D.C.; July 1991.

Speaker, "The Role of Load Research in DSM Evaluation," NYSEG Conference; Saratoga Springs, New York; May 1991.

Speaker, "The Role of Load Research in Demand Side Management" with Joseph Lopes; Northeast AEIC Load Research Conference; Farmington, Connecticut; September 1989.

Speaker, "The Role of Load Research in Demand Side Management," 1989 APPA Accounting, Finance, Rates and Information Systems Workshop; Chicago, Illinois; September 1989.

Speaker, "Demand Side Management; The Key to Measuring Success and Cost Recovery," Iowa Utility Association; Integrated Resource Planning Conference; Des Moines, Iowa; August 1989.

Speaker, "DSM Program Monitoring & Evaluation Workshop," Rochester, New York; December 1988.
Speaker, "The Massachusetts Joint Utility Monitoring Projects" with Eric P. Cody; Northeast Regional AEIC Load Research Conference; Farmington, Connecticut; September 1986.

Author, "The Load Research Process Above and Beyond PURPA," Public Utilities Fortnightly; March 18, 1982.

"Load Data Management and Analysis," EPRI RP1588-3; December 1981.

Co-Author, "Issues in Load Research," Topic Paper 3; EPRI Rate Design Study; 1981.

Instructor, "Load Research and Load Management Seminar," Stone and Webster Utility Management Development Course; New York (2 courses); 1980.

Speaker, "Allocating Revenues Between Service Classifications: Necessary Load Research," National Regulatory Research Institute; Ohio State University; 1980.

Speaker, "Issues in Load Research," EPRI Rate Design Study Executive Transfer Conferences; San Francisco, Kansas City, and Washington D.C.; 1980.

"How Electric Utilities Forecast," EPRI Peak Load Forecasting Methodologies; EPRI Symposium Proceedings; New Orleans, Louisiana; 1979.

"Report of the Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corporation pursuant to Article 3, Section 5, 112 of the Energy Law of New York State, Exhibit 7," LILCO Load Forecast Methodology; 1979.

Speaker, "Load Forecasting Working Group Chairman Reports (3)," Utility Modeling Forum (EPRI sponsored); San Francisco, California; 1979.

"Report of the Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corporation pursuant to Article 8, Section 149-b of the Public Service Law, Exhibit 7," LILCO Load Forecast Methodology; 1974-1978.

AFFILIATIONS

Association of Energy Engineers

American Statistical Association

American Economic Association

Mathematical Association of America

Omicron Delta Epsilon

Advisor to American Management Association

EDUCATION

St. John's University, M.B.A., Economic Theory, 1972

St. John's University, B.A., Economics, 1969

C.W. Post College, course work toward an MS, Management Engineering

Mr. Fitzpatrick has also completed course work in Engineering Economics, Load Research, Demand Forecasting in Electric Power Systems, Box-Jenkins Forecasting Techniques, logistic curve analyses; two and three stage multiple regression techniques; advanced econometric modeling and the utilization and interpretation of multiple regression models and associated analytical techniques. Mr. Fitzpatrick also holds a “Certificate of Mastery” in Reengineering from the Hammer Institute’s Speaker: Center for Reengineering Leadership.

RICHARD J. RUDDEN

Mr. Rudden is a generalist in the areas of energy industry change, strategic and business planning, financing, and organizational restructuring and analysis. He is a specialist in the practice areas of energy and utility strategy, pricing, financing, economic and regulatory policy analysis, economic analysis, and related management consulting. He is highly proficient in the management of large, complex and multi-disciplinary management consulting projects.

PROFESSIONAL EMPLOYMENT

1981 - Present	R.J. Rudden Associates, Inc. *Chairman, President & Chief Executive Officer*
1975 - 1981	Stone & Webster Management Consultants, Inc. *Vice President, Regulation Services Division*
1970 - 1975	Consolidated Edison Company of New York, Inc. *Divisional Manager, Rate Design; Rate Engineering Department*
1967 - 1970	U.S. Navy *Commissioned Officer*

PROFESSIONAL EXPERIENCE

Strategic and Business Planning, Merger and Acquisition Analysis

Mr. Rudden has been involved in many engagements in this area of the firm's practice. As the Responsible Officer for these projects, he has been asked to identify and screen potential merger or acquisition candidates, participate in the restructuring of financially-distressed assets and corporations, and assess the strategic compatibility of acquirer and the acquired, including reviews of their organizations, managements, and regulatory environments. He has also directed due-diligence reviews, the determination of enterprise value, and the analysis of the supply, distribution and market infrastructures of the parties to the transaction. He has also assisted members of the financial community in assessing the risks of increased competition and open access in electric utility industry. He has participated in joint venture and acquisition negotiations on behalf of the principals, and has testified on reorganization and bankruptcy issues. In addition, he has been involved in evaluating proposed utility municipalization/privatization activities, and was retained as the independent consultant to the Board of Directors of one utility that was the object of a proposed state takeover. In that project, he was responsible for overseeing an analysis of the market power exerted by the acquisition target. Mr. Rudden's clients have included the New York, Midwest and PJM Independent System Operators; Long Island Lighting Company (now LIPA); Fitch Investors Service, Inc.; J.P. Morgan Chase; Goldman Sachs; Macquarie Holdings; Edison Source; EON; Centrica; Sempra Energy; Hydro Quebec; NUI Corporation; Orange & Rockland Utilities; Norstar Energy

Limited Partnership; KCS Power Marketing, Inc.; Star Gas Partners; Blavin & Co.; EPRI; Macquarie Capital; ProLiance Energy, LLC; GE Nuclear Energy; the Equity Committee of Public Service Company of New Hampshire; PEPCO; Utah International; Philadelphia Gas Works; GWC Corporation; ENERGYiNTELLECT (New Zealand); State Street Bank & Trust Company; SHV Oil and Gas; Southern Union Company; a number of U.K.- and Asia-based utility acquirers; and a U.K. developer of cogeneration engines.

Utility Pricing and Regulatory Policy Analysis

Mr. Rudden has participated in both electric and gas pricing and cost analyses, and has held operational responsibilities within a major utility for cost analysis, tariff design and administration. He has experience in virtually every facet of utility pricing and has provided expert testimony before the FERC, state and Canadian provincial regulatory commissions, as well as civil and bankruptcy courts, on such issues as general regulatory policy, ISO/RTO rate design; revenue enhancement strategies; integrated resource planning; fully allocated and marginal costs; service unbundling and rate design; proforma adjustments and revenue requirements; sales and revenue forecasts; strategic and market sensitive pricing; incentive rate making, rate and regulatory polices for cogenerators, both with respect to rates for natural gas as a fuel, and electric standby, supplemental, maintenance and sale-back rates; revenue sharing and automatic adjustment mechanisms; by-pass; price elasticity and fuels switching; rate phase-in plans; transmission pricing; and other issues.

In addition, Mr. Rudden has testified on a diversity of other matters, such as utility revenue requirements, financial matters, sales forecasts, and proforma adjustments to test periods. Complementing his work in rate design, Mr. Rudden has also participated in a variety of projects relating to the establishment of new regulatory policies, including industry restructuring, competitive market analysis, market power issues, cogeneration policies, generic rate design issues, PURPA guidelines, regulatory aspects of utility bankruptcy, and price discrimination. A few of the clients for whom Mr. Rudden has performed these services include: the California ISO, PJM, the Midwest and MAPP ISOs; Con Edison; Energy West; China Light & Power; Seattle City Light; the City of Calgary Electric System (ENMAX); Long Island Lighting Company; Atlanta Gas Light Company; Chugach Electric Cooperative; Empire District Electric; Elizabethtown Gas Company; Philadelphia Gas Works; the Equity Committee for Public Service Company of New Hampshire; Southern Connecticut Gas; Vermont Gas Systems; Gulf States Utilities; Nova Scotia Power Corporation; Southern Union Gas Company; the U.S. Department of Energy; Bethlehem Steel; New Jersey Transit Corporation; Co-Steel; and AGL Gas Companies (Sydney, Australia).

Market Analysis, Sales Forecasting and Marketing

Mr. Rudden has directed or participated in a number of projects related to market analysis and forecasting, as well as the functional area of marketing. These projects include market research and segmentation analysis, new market entry strategies, market forecasting for both rate cases and other applications, analysis of declining customer use, the development of new unbundled products and services, load research, and customer attitude surveys. The results of his work have been used in expert testimony, business plans, joint venture and merger and acquisition activities, and client-internal reports. Mr. Rudden has also directed a number of studies that have assessed the changes in the competitive positions of both electric and gas utilities resulting from energy industry restructuring. His work includes the development of a framework for analyzing the market and financial risks of electric utilities, the costs of least-cost alternative power supplies under open access conditions, and the determination of the value of both natural and regional markets for power sold in the open access market. Mr. Rudden's clients in this area have included Edison Source; Atlanta Gas Light Company; Philadelphia Gas Works; Elizabethtown Gas Company; Con Edison; Star Gas Partners; GE Nuclear Energy; Niagara Mohawk Power Corporation; Gas Company of New Mexico; Rochester Gas & Electric Corporation; KCS Power Marketing, Inc.; Utah International; SHV Oil and Gas; Long Island Lighting Company; the Department of Energy, Mines and Resources, Canada; the Columbia Gas Distribution Companies; and IBC Fitch Investors Service, Inc.

Corporate and Project Financing

Mr. Rudden has participated in numerous energy project analyses and financings. Matters with respect to which he has offered advice and expert testimony include: power purchase and sales agreements; fuels availability; utility interconnects; utility standby, back up and power purchase contracts; the market for project power and project revenue streams; wheeling options for project power; and regulatory policies. His expertise has been applied in a variety of ways, including due-diligence reviews, project risk identification and management, contract negotiations, business plans, feasibility analysis, and testimony. Clients for whom he has performed this work include Donaldson, Lufkin & Jenrette; Macquarie; Goldman, Sachs & Company; a group of Detroit pension funds; Inter-Continental Energy; KIAC Project Partners; State Street Bank & Trust Company; Allegheny Power System; The Royal Banks of Canada and Scotland; Bank of Montreal; Amtrak; Long Island Lighting Company; Arkla, Inc.; the University of Pennsylvania; the State University of New York at Stony Brook; Utah International; Reckson Associates; and the Montecristi Corporation.

Generation and Transmission Planning

Mr. Rudden has been involved in a variety of consulting projects and employment positions dealing with the issues of generation and transmission planning, especially as they relate to electric ratemaking, establishment of regulatory policies, and RTO/ISO formation and regulation. Mr. Rudden has dealt with these matters in the context of FERC Orders 2000 and 888, PURPA regulations, the development of wheeling and wholesale rates, cogeneration project feasibility analyses, utility bankruptcies, generation and transmission reliability studies, strategic planning, and the analysis of regional markets for bulk power. He has also directed benchmarking studies related to T&D operations, and an analysis of historical reliability performance and the establishment of reliability objectives in the context of utility budgeting and performance-based ratemaking. In addition, while at Con Edison, Mr. Rudden had responsibilities in the areas of generation operations and transmission load flow analyses. Utilities and other clients with respect to whom Mr. Rudden has provided consulting services in this area include: the New York ISO; Sempra; the U.S. Department of Energy; El Paso Electric Company; Entergy/Gulf States Utilities; the Canadian Department of Energy, Mines and Resources; Chugach Electric Cooperative; ENMAX/City of Calgary Electric System; Amtrak; NU/Public Service Company of New Hampshire; Philadelphia Electric Company; Baltimore Gas & Electric Company; State Street Bank &Trust Company; and Nantahala Power & Light Company.

Gas Supply and Transportation Planning

Mr. Rudden has performed gas supply and transportation studies for both utility companies and non-utility marketers, transporters and end-users of natural gas. He has advised cogenerators on gas acquisition policies; LDCs on transportation policies, pricing strategies, and bypass issues; large end-users on appropriate price levels for purchased gas and related contractual terms and conditions; and third party developers and financial institutions with regard to fuel supplies to independent power projects. In addition, he has directed projects relating to gas supply modeling for the purposes of least-cost planning, marginal costing, and merger and acquisition work. Clients for whom Mr. Rudden has provided these services include: Atlanta Gas Light Company, Energy West/Great Falls Gas Company, NUI Corporation, GWC Corporation, Intercontinental Energy; Southern Union Company, Elizabethtown Gas Company, Niagara Mohawk Power Corporation, Providence Memorial Hospital, Standard Chlorine of Delaware, Sithe Energies/Bank of Montreal, and State Street Bank & Trust Company.

Integrated Resource Planning and Demand-Side Management

Mr. Rudden has been responsible for many of the firm's projects within the integrated resource planning area. Projects which the firm has performed include the development of complete integrated resource plans for Atlanta Gas Light Company, Providence Gas Company, and The Peoples Gas Light and Coke Company; a critical review and evaluation of both Commonwealth Edison's Least-Cost Plan and Entergy's regional IRP; a review of the merged PacifiCorp-Utah Power & Light least cost plan as applied to the Utah division; the evaluation of proposed DSM programs by TransAlta Utilities and Alberta Power Corporation on behalf of ENMAX/ City of Calgary Electric System; identification and quantification of least cost gas supply plans for NUI Corporation and Southern Union Company, both in connection with proposed reorganization and acquisition activities; the development of an integrative utility planning methodology for the U.S. Department of Energy; and the development of PC-based gas supply models for two LDCs in conjunction with least-cost supply planning. Mr. Rudden has also been involved in the review and critique of Public Service Company of New Hampshire's demand-side management (DSM) program within the context of its Chapter 11 Bankruptcy proceeding, and Oklahoma Natural Gas with regard to the DSM programs of Oklahoma Gas & Electric Company. Finally, Mr. Rudden has assisted a variety of industrial clients in developing and implementing least-cost energy purchasing strategies, such as Amtrak, Reckitt & Coleman, New Jersey Transit, Bethlehem Steel, Standard Chlorine of Delaware, and Geneva Steel.

Organizational Consulting

Mr. Rudden's years of experience and his diverse technical background have made him very effective as an organizational consultant, especially in such areas as organizational structuring, cultural change, forecasting and planning processes, rate and regulatory support, information systems, market and load research, marketing, and gas supply. As a part of these assignments, Mr. Rudden has provided leadership not only at the higher levels associated with strategic plan implementation, but also at the more "granular" levels of operations. He has reviewed and made recommendations pertaining to operating policies and procedures, strategic mission and objectives statements, program implementation plan, spans of control, staffing levels and qualifications, culture change, salary structures and bonus plans, and information systems support. His clients have included Energy West; Star Gas Partners, Edison Source; Rochester Gas and Electric Corporation; the New York Independent

System Operator; Western Gas Interstate Pipeline Company; Con Edison; Norstar Energy Partners, LLC; the City of Colorado Springs Municipal Utility System; the City of Garland, Texas; a confidential New York State gas distribution company; Philadelphia Gas Works; EPRI; Atlanta Gas Light Company; and GWC Corporation.

Information Systems Support

Mr. Rudden has been responsible for the specification of user requirements, conceptual system design, and components of detail system design, and for the testing and acceptance of a number of information technology and software development projects. These systems related to costing and rate design, complete FERC rate filing requirements, forecasting, load research, market information systems, least-cost energy acquisition, utility billing and revenue reporting systems, integrated supply and demand side planning, litigation support systems, and financial analysis and reporting. Clients whom Mr. Rudden has served in these areas include: Valero Energy Corporation, El Paso Electric Company, Con Edison, Utah International, Southern Connecticut Gas Company, Amtrak, Western Gas Interstate, Southern Union Company, and NUI Corporation.

Litigation Support

As an integral part of the service that he has provided clients in the above areas, Mr. Rudden has frequently offered expert testimony before state regulatory commissions, city councils, the FERC, civil court, Federal Bankruptcy Court and Canadian regulators. This includes testimony before the U.S. Bankruptcy Court in the Public Service Company of New Hampshire Chapter 11 proceedings; before a civil court on behalf of a plaintiff in a class action suit against a facility owner, alleging overcharges for electric service; before the FERC on both electric and natural gas matters; and before many state regulatory commissions on a variety of costing, rate design, revenue requirement, market, economic and regulatory policy issues. In all, Mr. Rudden has submitted testimony in approximately 37 proceedings, in 19 jurisdictions.

PUBLICATIONS AND PRESENTATIONS

“A Primer on the Regulatory Environment for Energy Utilities,” presented at the American Gas Association’s Financial Forum; Bonita Springs, Florida; May 2, 2004.

“Utility Regulatory Preparedness,” presented at the American Gas Association’s Rate & Regulatory Issues Seminar; Phoenix, Arizona; April 6, 2004.

“Regulators and Regulations,” presented at the American Gas Association Workshop, Introduction to the Energy Industry;” New York, New York; March 15, 2004.

“Utility Rate Case Preparedness – A Commentary Based on Survey Results,” presented at the EEI Strategic Issues Committee; October 17, 2003.

“The Mother of All Rate Cases,” published by *Hart’s Energy Markets*, October 2003.

"The Energy Marketplace: The Advisors Weigh-In," moderator at the North American Energy Standards Board 2nd Annual Meeting; Austin, Texas; September 16-17, 2003.

"Massive North American Blackout and the Lack of Investment," interview published in *World Interview*, The Nihon Keizai Shimbun Japan Economic Journal; September 8, 2003.

"The Shock Heard 'Round The World Or ... The August 14th Birth Of The United Grid Of America," August 2003.

"Distribution Reliability and Power Quality: The Next Industry Time Bomb?" June 2002 (co-authored).

"Legal Document Management in the Energy Industry: Moving From Information Flow to Knowledge Leadership," June 2002 (co-authored).

"Mergers & Acquisitions, 2002: An Urgent Need for Strategic Clarity," *Public Utilities Fortnightly*; April 15, 2002 (co-authored).

"What Has the Energy Industry Learned From Deregulation?" presented at the American Gas Association's 20th Annual Bankers Conference; New York, New York; November 11-13, 1998.

"Ten Hurdles to Full-Scale Competition in the U.S. Electric Power Industry," presented at the National Association for Business Economics; Washington, D.C.; October 4-7, 1998.

"Utility Strategic Planning," presented at the Exnet Utility Strategic Planning Seminar; Washington, D.C.; July 14-15, 1997.

"Winners in Deregulation—Electric or Gas?" presented at ANR Pipeline Company's 1997 Business Strategy Meeting, Ideas for the Future; Phoenix, Arizona; March 14, 1997.

"Electric Industry Restructuring and its Affects on the U.S. Natural Gas Industry," presented at the International Centre for Gas Technology Information Seminar; Tokyo, Japan; September 18, 1996.

"Product Pricing Considerations in Energy Company Mergers," presented at the Institute of Gas Technology's Financing the Fusion of the Gas and Electric Industries Conference; New York, New York; July 24, 1996 (co-authored).

"The Barbarians at the City Gate," presented at the American Gas Association's *Competing in a Restructuring World: Becoming the Customer's Choice*; Orlando, Florida; April 10, 1996.

"Electric Industry Restructuring 101: Trends in State PUC Regulatory Policies, Attitudes, and Opinions Regarding Electric Industry Changes" and "Electric Industry Restructuring 102: Implications of Competitive Electricity Price Trends and Pricing Strategies for Natural Gas Markets," presented at the American Gas Association's Industrial Marketing Committee Meeting; Salt Lake City, Utah; April 1, 1996.

“Operating in a Competitive Environment: Will the Market Stay the Way It Is?,” presented at the ZECO’s Conference on *Operating in a Competitive Environment*; Salt Lake City, Utah; March 5, 1996.

Effect of Electric Industry Restructuring on the Competitive Price Position of Natural Gas, February 1996 (co-authored).

1995 Survey of State Regulatory Commissions Regarding Electric Utility Competition, December 1995 (co-sponsored by the American Gas Association).

“Electric Industry Change: Bringing Order Out of Chaos,” presented at the American Gas Association’s Conference on Electric Industry Restructuring; Baltimore, Maryland; October 26, 1995.

“Electric Industry Restructuring: Its Implications for the Natural Gas Industry,” presented at the American Gas Association Rate Committee Meeting; New Orleans, Louisiana; April 4, 1995.

“The Electric Industry Change: The Views of State Regulators,” presented at the AIC Conference on *Positioning for the New Integrated Gas & Electric Power Market*; New York, New York; March 27, 1995.

“The Implications of Electric Restructuring for the Use of Natural Gas,” presented at the American Gas Association’s Symposium on *The Effects of Deregulation in the Electric Industry on Gas Markets*; Albuquerque, New Mexico; March 20, 1995.

“Competitive Forces and Market Risks: Regulators’ Views of the Future Electric Utility Industry,” *Public Utilities Fortnightly*, November 1994 (co-authored).

“A Survey of State Regulatory Commissions on Competitive Forces and Market Risks in the Electric Utility Industry,” presented before the Public Service Company of Colorado; Denver, Colorado; November 1994.

“The Future Power Industry—Defining the Boundaries,” *Cogeneration and Competitive Power Journal*, Fall 1994.

“Competition in the Electric Markets,” *The Energy Daily—Special Insert*, October 1994.

“A Survey of State Commissions on Electric Industry Competition,” presented at the *Energy Daily’s* Impact of Retail Competition on the Electric Markets Conference; San Diego, California; September 1994.

R.J. Rudden Associates, Inc. 1994 Survey of State Regulatory Commissions Regarding Electric Utility Competition, September 1994 (co-authored).

“The EPAct of 1992: New Players, New Plays,” presented at the Association of Energy Engineers Competitive Power Congress; Philadelphia, Pennsylvania; June 9, 1994.

"Quantifying Competitive Forces in the Electric Industry," *The Rudden Resource—Special Edition*, June 1994.

"Electric Utility Competition: A Survey of Regulators," presented at the Transmission Access, Wheeling and Deregulation of America's Utilities—A National Conference and Summit Meeting; Arlington, Virginia; May 23, 1994.

"Changing Financial Risks in the Restructured Gas Industry," presented at the Tejas Power Corporation's Seventh Annual Conference on Industry Issues, April 1994.

"Electric Utilities in the Future," *Fortnightly*, April 1994 (co-authored).

"Electric Utility Competition: A Survey of State Regulators," presented at the Edison Electrical Institute's 28th Financial Conference; Orlando, Florida; November 1993.

"Electric Utilities Competitive Risk: A Commentary," presented at Fitch Investors Service's Electric Utility Roundtables; Boston, Massachusetts; Hartford, Connecticut; Chicago, Illinois; and Minneapolis, Minnesota; August 1993.

"Integrated Resource Planning: Ensuring Technological Excellence in the Natural Gas Industry," presented at the Southern Gas Association's 85th Annual Meeting, April 1993.

"IRP and its Impacts on Architects and Engineers," presented at the Southern Gas Association's Southern Conference for Architects and Engineers, October 1992.

"Integrated Resource Planning: Nationwide Trends," presented at the American Gas Association Rate Committee Meeting, April 1992.

"IRP: A Forecaster's Fantasy," presented before the American Gas Association's Statistics and Load Forecast Methods Committee Seminar on Long Range Forecasting for Integrated Resource Planning, March 1992.

"Integrated Resource Planning—A Strategic Marketing Perspective," presented before the Southern Gas Association Marketing Executives Committee, February 1992.

"Supply Side Marginal Costs as an Element of Integrated Demand and Supply Side Planning, Natural Gas Strategies: Integrating Supply Planning, Marketing and Pricing," presented at before the American Gas Association Rate Committee and Marketing Section, May 1989.
"The Impact of Current Market Changes on Distributors: Diversification Strategies and Regulatory Issues," presented at the Fifteenth Annual Rate Symposium, University of Missouri, February 1989.

"Natural Gas: Issues and Outlook, Unbundling at the Distribution Level," presented before The Energy Bureau Inc., October 1988.

"Natural Gas, Cogeneration, and Merchant Generation in New England: Pipeline Capacity Constraints," presented before the American Bar Association, October 1987.

"Utility Rate Unbundling," presented at the American Gas Association Advanced Regulatory Seminar, University of Maryland, 1986-1990.

"Effective Diversification Strategies and Regulatory Issues Surrounding Diversification in a Competitive Market," presented at the IGT Conference, November 1986.

"Cogeneration Financing in a Changing Utility Market," presented at the Proceedings of the 9th World Energy Engineering Conference, October 1986.

"The Strategic Utility Response to Power Wheeling Initiatives," presented before the Energy Management Division Conference of the Electric Council of New England, August 1986.

"How Can Cogenerators Take Advantage of Current Natural Gas Dislocations?" *Strategic Planning and Energy Management*, Spring 1985.

"The Economics of Gas-Fired Cogeneration," presented before the American Gas Association Rate Committee, April 1985.

"Cogeneration: the Strategic Opportunity," presented at the Southern Union Gas Cogeneration Seminar and Workshop, December 1984.

"Choices," presented before the ANR Pipeline Company Annual Marketing Meeting, June 1984.

"Natural Gas Regulation," presented before the New England Gas Users Group, March 1984.

"A Survey of Rate Case Computerization," presented before the Rate Committee of the American Gas Association, September 1983.

"Natural Gas Deregulation: Options at the Distribution Level," presented before the Seventh Annual Public Utilities Conference at the University of Texas, July 1982.

"The Public Utilities Regulatory Policies Act of 1978 - A Wolf in Sheep's Clothing," presented before the Northwest Public Power Association Consumer Services and Communications Conference, August 1979.
"Regulatory Guidelines and Standards Under the Public Utilities Regulatory Policies Act of 1978," presented before the Fifth Annual Symposium on the Problems of Regulated Industries, February 1979.

"The DOE Ratemaking Guidelines Project," presented before the Northwest Public Power Association, January 1979.

"New Ideas in Gas Rate Design," presented before the Texas Gas Association, June 1978.

"A Technical and Organizational Overview of the Nova Scotia Rate and Load Control Experiment," presented before the Canadian Electrical Association, March 1978.

"Another Kind of Audit," *Public Utilities Fortnightly*; October 13, 1977.

AFFILIATIONS AND HONORS

Board Member, North American Energy Standards Board

Financial Associate, American Gas Association

Marketing Associate, American Gas Association

Associate Member, Edison Electric Institute

Member, EEI Strategic Issues Committee

Member, National Association of Business Economists; Corporate Planning Roundtable

Member, American Gas Association Rate Committee

Member, Association of Energy Service Professionals

Member, Society of Gas Lighting

Omicron Delta Epsilon (Honor Society in Economics)

Past Member, Presidential Cogeneration/Energy Advisory Committee, State University of New York at Stony Brook

Past Member, Advisory Board, W. Averell Harriman School for Management and Policy, State University of New York at Stony Brook

EDUCATION AND LICENSES

Queens College, City University of New York, B.A., Economics, 1967, with Honors

New York Graduate School of Business Administration, course work in finance and economics for M.B.A.

NASD licensed Securities Representative (Series 7 and 63) and General Securities Principal (Series 24).

JOSEPH T. TRAINOR

Mr. Trainor is an electrical engineer with specialties in the areas of cost of service and financial modeling. He has broad experience in the fields of unbundled cost of service modeling, statistical analysis, forecasting, load research and analysis, transmission system benchmarking, Form 1 and NERC Form 411 data analysis, and database management.

Mr. Trainor is the architect and implementer the Rudden Electric and Gas Cost of Service Model. He has performed both electric and gas cost of service and marginal cost of service projects for a variety of clients, as well as benchmarking studies for transmission entities. He created models to forecast revenue requirements. He has also created models to perform economic, rate and financial valuations of multi-jurisdictional utilities for the purpose of investment. He analyzed electric load data for State Agencies to support its competitive procurement. He has assisted in the economic evaluations of Power Plants to assess their performance in a deregulated environment. He has developed systems for managing large and complex data sets for energy prices and costs. He has preformed statistical sampling and forecasting for the purpose of load forecasting and investment.

In addition to his utility and energy industry analytical skills, Mr. Trainor's broader IT expertise includes, application programming and database management. He has extensive experience in supporting computer user applications, including the Microsoft Office Suite, Lotus and WordPerfect, and has created applications in VB/VBA, FoxPro, C, Access and Excel.

PROFESSIONAL EMPLOYMENT

1998 - Present	R.J. Rudden Associates, Inc. *Senior Consultant* *Director of Information Systems*
1994 - 1998	MUZE, INC., NY (Software Development Firm) *Supervisor of Software Updates*

- Produced 10 software applications monthly used for the retail of entertainment products.

PROFESSIONAL EXPERIENCE

Computer Modeling and Database Creation

Mr. Trainor has utilized his modeling skills to develop and enhance analytical tools, as well as enhance and upgrade the R.J. Rudden Cost of Service Models. The enhancements to the models include a VBA-user interface that allows the user to navigate the model, analyze the data, and perform maintenance functions through menu routines. In addition to the numerous PC-based programs, he has experience in running, modifying and extracting information from databases that contain hundreds of thousands of records and made them available to clients using a graphical user interface. Mr. Trainor has designed and used computer models to perform economic, rate and financial planning. He has analysis customer databases to perform statistical sampling. He is skilled in multiple spreadsheet and database application software, including Microsoft Excel, Access, and FoxPro. Clients for whom Mr. Trainor has served in these areas include: Nissequogue Cogen Partners, Connecticut Natural Gas, Baltimore Gas and Electric Company, Kansas Gas Service and Philadelphia Gas Works.

Electric and Gas Costing

Mr. Trainor has performed both electric and gas cost of service and marginal cost of service projects. He has developed the special studies, interviewed personnel and performed other data gathering procedures necessary to obtain all of the information needed to perform both Marginal and Cost of Service Studies. Mr. Trainor has completed these studies for both wholesale and retail clients using an enhanced version the R.J. Rudden Cost of Service Study Model. The completion of the Cost of Service Study included Functionalizing, Classifying and the allocation of all the Utility's Rate Base, operating and maintenance costs, production costs, gas costs, taxes and working capital costs, development of all Allocators, and implementation of billing determinants for rate design. Clients for whom Mr. Trainor has served in these areas include: Philadelphia Gas Works, Baltimore Gas and Electric, Keyspan, MidWest Energy, Energy West Resources, and Niagara Mohawk Power Corporation.

Competitive Procurement

Mr. Trainor has participated in a project to procure electric supply for a group of State Agencies. He assisted in the creation of the Request for Proposal, Appendixes and Exhibits. He managed the collection of the historical load data by obtaining, cleaning and presenting the data. He developed an easy to use front-end application, which became part of the RFP and was posted on the Rudden Website for distribution to Bidders.

Energy Project Financing and Analysis

Mr. Trainor has participated in projects in this area. Participation consists of assisting in economic and financial modeling of multi-jurisdictional utilities for the purpose of investment analysis. Mr. Trainor has assisted in performing economic and rate forecast modeling for Bond issuance and financial analysis of regulated utilities for investment purposes. Mr. Trainor has participated in economic and financing analyses evaluating the performance and profitability of electrical power plants. He has assisted in the economic evaluations of Power Plants to project their performance in a deregulated environment. Clients for whom Mr. Trainor has served in these areas include: Enmax Power Corporation, Nissequogue Cogen Partners, and Blavin & Company.

EDUCATION

Long Island University, New York, Master of Business Administration, 2003

Manhattan College, New York; Bachelor of Electrical Engineering, 1993

R. J. RUDDEN ASSOCIATES, INC.

R.J. Rudden Associates, Inc. (Rudden) provides economic, management and financial consulting services to utilities and their customers throughout North America and internationally. Founded in 1981, we have approximately 70 consultants. Our headquarters office is in Hauppauge, New York with regional offices in Washington, D.C. and San Francisco, California. Rudden's major practice areas include utility pricing; regulatory policy analysis; strategic and market planning; market research, demand forecasting and marketing; merger and acquisition assistance; generation and transmission planning; energy project management, financing and analysis; fuels analysis and acquisition; and litigation support and testimony. Our clients include electric and gas utilities subject to FERC and state regulation, energy producers and consumers, other industrial and commercial organizations, financial institutions and the U.S. and Canadian government.

APPENDIX B
COMPONENT ACCURACY TABLES

Residential Rate Class

FORECAST ACCURACY - TOTAL YEAR VOLUMES for RESIDENTIAL RATE M2 (S)

Year	Normalized Actual	Forecast	Difference	Actual % Diff.	ABS % Diff.
1994	2,496	2,539	44	1.73%	1.73%
1995	2,486	2,485	1	-0.03%	0.03%
1996	2,521	2,439	82	-3.36%	3.36%
1997	2,500	2,408	92	-3.81%	3.81%
1998	2,392	2,397	5	0.22%	0.22%
1999	2,334	2,452	117	4.79%	4.79%
2000	2,317	2,364	47	1.99%	1.99%
2001	2,221	2,267	46	2.04%	2.04%
2002	2,211	2,183	28	-1.27%	1.27%
2003	2,162	2,158	5	-0.21%	0.21%
			Average from 94-00	0.22%	2.28%
			Average from 01-03	0.19%	1.18%

FORECAST ACCURACY - TOTAL YEAR VOLUMES for RESIDENTIAL RATE 01 (N)

Year	Normalized Actual	Forecast	Difference	Actual % Diff.	ABS % Diff.
1994	824	837	12	1.49%	1.49%
1995	795	795	1	-0.06%	0.06%
1996	780	794	14	1.74%	1.74%
1997	779	752	27	-3.59%	3.59%
1998	748	752	4	0.51%	0.51%
1999	755	756	1	0.13%	0.13%
2000	757	747	10	-1.30%	1.30%
2001	714	723	9	1.27%	1.27%
2002	695	706	11	1.55%	1.55%
2003	697	683	14	-2.07%	2.07%
			Average from 94-00	-0.15%	1.26%
			Average from 01-03	0.25%	1.63%

Commercial Rate Classes

FORECAST ACCURACY - TOTAL YEAR VOLUMES for COMMERCIAL RATE M2 (S)

Year	Normalized Actual	Forecast	Difference	Actual % Diff.	ABS % Diff.
1994	1,470	1,550	80	5.17%	5.17%
1995	1,478	1,547	69	4.46%	4.46%
1996	1,533	1,409	125	-8.85%	8.85%
1997	1,528	1,368	160	-11.71%	11.71%
1998	1,443	1,398	45	-3.25%	3.25%
1999	1,440	1,504	63	4.22%	4.22%
2000	1,397	1,444	47	3.22%	3.22%
2001	1,374	1,373	1	-0.09%	0.09%
2002	1,381	1,299	82	-6.33%	6.33%
2003	1,350	1,334	16	-1.24%	1.24%
			Average from 94-00	-0.96%	5.84%
			Average from 01-03	-2.55%	2.55%

FORECAST ACCURACY - TOTAL YEAR VOLUMES for COMMERCIAL RATE 01 (N)

Year	Normalized Actual	Forecast	Difference	Actual % Diff.	ABS % Diff.
1994	275	287	13	4.37%	4.37%
1995	263	262	1	-0.25%	0.25%
1996	264	270	6	2.24%	2.24%
1997	263	256	8	-2.93%	2.93%
1998	241	255	14	5.31%	5.31%
1999	229	248	19	7.60%	7.60%
2000	247	248	0	0.08%	0.08%
2001	245	234	11	-4.81%	4.81%
2002	230	238	8	3.28%	3.28%
2003	231	232	1	0.46%	0.46%
			Average from 94-00	2.35%	3.26%
			Average from 01-03	-0.36%	2.85%

APPENDIX C

SUMMARY OUTPUT RES 01 VOL			HETEROSCEDASTICITY TEST "Constant Variance Confirmed"		
Regression Statistics			*Regression Statistics*		
Adjusted R Square		0.9837	Adjusted R Square	-	0.0066
Standard Error		4,442.11			
Observations		154.00			*t Stat*
Durbin's h		3.77	Residuals	-	0.00
MAPE		1.0%			
		Coefficients	*Standard Error*		*t Stat*
Intercept	-	16,820.76	2,589.06	-	6.50
VOL lag 1m		0.12	0.04		3.12
CUST		0.15	0.02		8.49
PRICE LAG 1M	-	13,437.33	6,362.45	-	2.11
HDD Jan		94.89	3.25		29.23
HDD Feb		89.03	4.74		18.79
HDD Mar		80.79	4.71		17.16
HDD Apr		69.17	6.00		11.53
HDD May		53.92	7.68		7.02
HDD Sept		66.49	8.49		7.83
HDD Oct		72.47	3.87		18.74
HDD Nov		87.86	2.79		31.47
HDD Dec		88.15	2.88		30.56
DUMMY VOL 3D MAY-00		19,147.19	4,624.36		4.14
DUMMY VOL 3D OCT-00		16,091.72	4,615.00		3.49
DUMMY VOL 3D Jan-03		20,345.54	4,688.80		4.34

SUMMARY OUTPUT RES 01 USE			HETEROSCEDASTICITY TEST "Constant Variance Confirmed"		
Regression Statistics			*Regression Statistics*		
Adjusted R Square		0.9907	Adjusted R Square	-	0.0065
Standard Error		16.00			
Observations		155.00			*t Stat*
D W Test		1.87	Residuals	-	0.00

		Coefficients	*Standard Error*		*t Stat*
Intercept		688.21	94.69		7.27
Price (Ex. Summer mnths)	-	41.50	19.83	-	2.09
R.F.E.I	-	823.17	126.18	-	6.52
HDD Jan		0.52	0.01		68.28
HDD Feb		0.51	0.01		58.24
HDD Mar		0.47	0.01		45.73
HDD Apr		0.43	0.02		27.59
HDD May		0.37	0.03		12.69
HDD Sept		0.35	0.04		8.41
HDD Oct		0.38	0.02		19.74
HDD Nov		0.46	0.01		37.97
HDD Dec		0.47	0.01		53.11
Dummy May-00		101.22	16.58		6.10

SUMMARY OUTPUT RES M2 VOL		**HETEROSCEDASTICITY TEST "Constant Variance Confirmed"**	
Regression Statistics		*Regression Statistics*	
Adjusted R Square	0.9886	Adjusted R Square	- 0.0061
Standard Error	11,608.66		
Observations	167.00		*t Stat*
Durbin's h	5.70	Residuals	- 0.00
MAPE	1.3%		

	Coefficients	*Standard Error*	*t Stat*
Intercept	- 58,701.68	8,061.46	- 7.28
VOL Lag 1m	0.09	0.03	3.01
CUST	0.15	0.02	9.17
PRICE Lag 1m	- 338.27	185.69	- 1.82
HDD Jan	375.87	10.82	34.74
HDD Feb	363.13	14.76	24.60
HDD Mar	358.68	14.71	24.39
HDD Apr	315.95	21.03	15.02
HDD May	254.74	27.48	9.27
HDD Sept	161.15	37.86	4.26
HDD Oct	267.84	13.61	19.67
HDD Nov	321.18	8.85	36.30
HDD Dec	375.73	8.40	44.74
Dummy Vol Feb-00	44,979.67	12,077.28	3.72
Dummy Vol Jan-03	54,731.76	12,289.98	4.45

SUMMARY OUTPUT RES M2 USE		HETEROSCEDASTICITY TEST "Constant Variance Confirmed"	
Regression Statistics		*Regression Statistics*	
Adjusted R Square	0.9969	Adjusted R Square	- 0.0060
Standard Error	9.07		
Observations	168.00		*t Stat*
D W Test	1.56	Residuals	- 0.00

	Coefficients	*Standard Error*	*t Stat*
Intercept	386.54	52.66	7.34
R.F.E.I	- 425.04	70.17	- 6.06
Price(Ex. Summer mnths)	- 0.48	0.11	- 4.26
HDD Jan	0.64	0.01	117.76
HDD Feb	0.63	0.01	102.35
HDD Mar	0.62	0.01	89.01
HDD Apr	0.59	0.01	52.89
HDD May	0.52	0.02	24.16
HDD Sept	0.31	0.04	7.96
HDD Oct	0.44	0.01	30.12
HDD Nov	0.52	0.01	60.94
HDD Dec	0.60	0.01	99.19
Dummy Use Jan-90	33.26	9.44	3.52
Dummy Use Jan-00	65.81	9.49	6.94
Dummy Use feb-00	34.97	9.42	3.71

SUMMARY OUTPUT **COM M2 VOL**		**HETEROSCEDASTICITY TEST** **"Constant Variance Confirmed"**	
Regression Statistics		*Regression Statistics*	
Adjusted R Square	0.9860	Adjusted R Square	- 0.0061
Standard Error	8,283.36		
Observations	167.00		*t Stat*
Durbin's h	2.66	Residuals	0.00
MAPE	1.5%		

	Coefficients	*Standard Error*	*t Stat*
Intercept	- 38,960.44	7,569.28	- 5.15
CUST	0.97	0.15	6.63
PRICE NO LAG	- 71.72	125.75	- 0.57
LAG VOL	0.06	0.04	1.77
HDD Jan	241.42	7.98	30.26
HDD Feb	244.19	10.48	23.31
HDD Mar	242.50	10.63	22.82
HDD Apr	225.27	15.98	14.09
HDD May	185.58	20.11	9.23
HDD Sept	95.68	26.90	3.56
HDD Oct	191.56	9.70	19.76
HDD Nov	242.01	6.57	36.81
HDD Dec	247.11	6.85	36.07
Dummy VOL Mar'00	50,185.44	8,751.49	5.73
Dummy VOL Apr'00	57,583.38	8,689.89	6.63

SUMMARY OUTPUT COM M2 USE		HETEROSCEDASTICITY TEST "Constant Variance Confirmed"	
Regression Statistics		*Regression Statistics*	
Adjusted R Square	0.9902	Adjusted R Square	- 0.0060
Standard Error	103.09		
Observations	168.00		*t Stat*
D W Test	1.76	Residuals	- 0.00

	Coefficients	*Standard Error*	*t Stat*
Intercept	- 5,573.22	1,229.93	- 4.53
C.F.E.I	6,039.80	1,240.89	4.87
HDD Jan	3.82	0.04	86.34
HDD Feb	3.93	0.05	77.49
HDD Mar	3.89	0.06	66.89
HDD Apr	3.78	0.10	39.20
HDD May	3.11	0.18	17.12
HDD Sept	1.08	0.33	3.26
HDD Oct	2.87	0.12	23.83
HDD Nov	3.70	0.07	50.91
HDD Dec	3.81	0.05	74.50
Dummy Use Mar-00	655.20	105.64	6.20
Dummy Use Apr-00	805.27	107.42	7.50

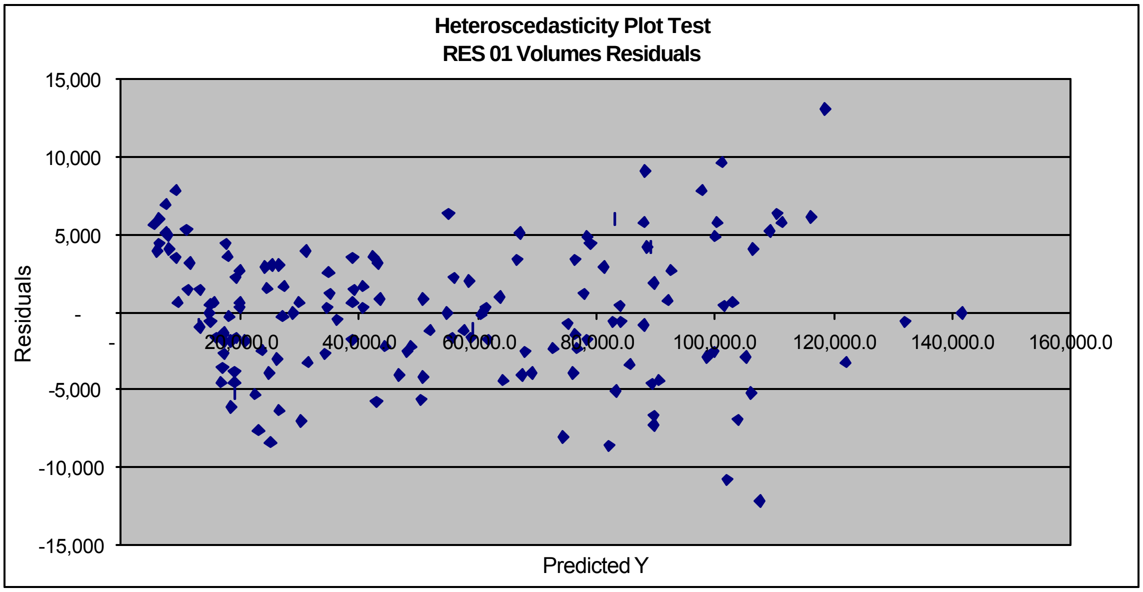
SUMMARY OUTPUT COM 01 VOL			HETEROSCEDASTICITY TEST "Constant Variance Confirmed"			
Regression Statistics			*Regression Statistics*			
Adjusted R Square		0.9896	Adjusted R Square		-	0.0068
Standard Error		1,352.19				
Observations		150.00				*t Stat*
Durbin's h		3.16	Residuals			0.00
MAPE		1.8%				
		Coefficients		*Standard Error*		*t Stat*
Intercept	-	2,121.44		1,268.81	-	1.67
CUST		0.30		0.07		4.08
PRICE	-	1,281.48		2,040.20	-	0.63
Lag VOL	-	0.03		0.04	-	0.70
HDD Jan		40.18		1.17		34.34
HDD Feb		41.18		1.65		24.98
HDD Mar		38.78		1.69		22.94
HDD Apr		32.62		2.23		14.63
HDD May		23.11		2.54		9.09
HDD Sept		15.02		2.68		5.61
HDD Oct		28.52		1.17		24.38
HDD Nov		34.04		0.93		36.49
HDD Dec		37.78		0.99		38.02
Dummy vol May-00		6,738.85		1,405.59		4.79
Dummy vol Sep-00		4,367.96		1,441.44		3.03

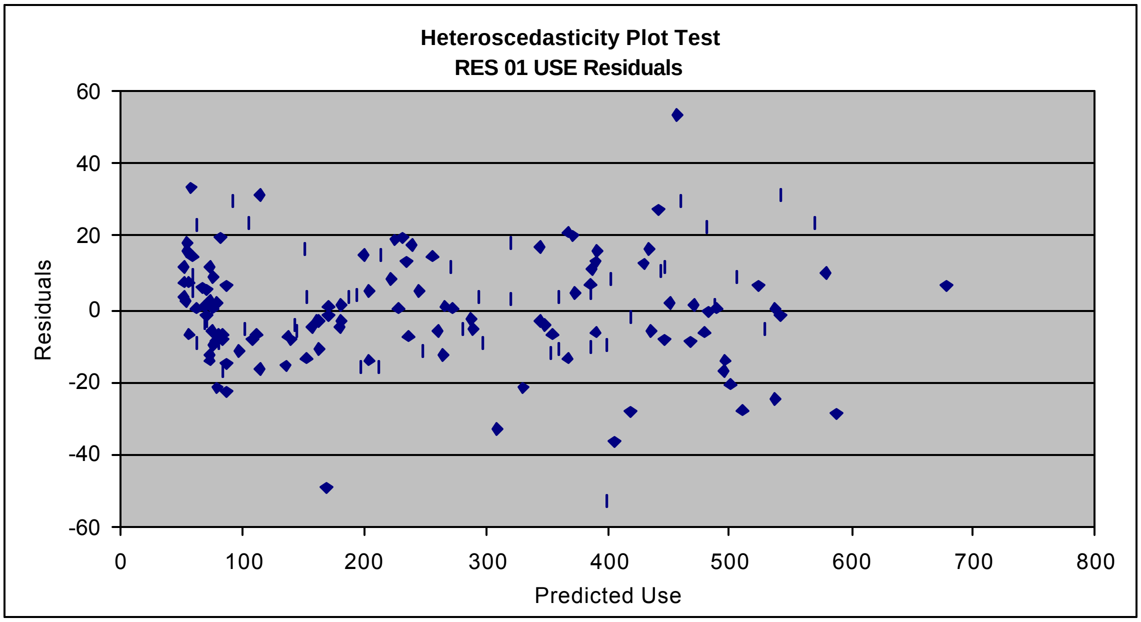
SUMMARY OUTPUT COM 01 USE			HETEROSCEDASTICITY TEST "Constant Variance Confirmed"		
Regression Statistics			*Regression Statistics*		
Adjusted R Square		0.9894	Adjusted R Square	-	0.0067
Standard Error		63.41			
Observations		151.00			*t Stat*
D W Test		1.40	Residuals	-	0.00
		Coefficients	*Standard Error*		*t Stat*
Intercept	-	7,140.28	787.99	-	9.06
Price(Ex. Summer mnths)	-	261.89	232.02	-	1.13
C.F.E.I		7,387.19	794.25		9.30
HDD Jan		1.87	0.05		38.91
HDD Feb		1.91	0.06		34.69
HDD Mar		1.80	0.06		28.20
HDD Apr		1.54	0.10		15.08
HDD May		1.19	0.19		6.38
HDD Sept		0.90	0.27		3.29
HDD Oct		1.48	0.12		11.97
HDD Nov		1.64	0.08		20.94
HDD Dec		1.77	0.06		31.51
Dummy Use May-00		323.56	65.84		4.91
Dummy Use Aug-00		216.46	64.42		3.36

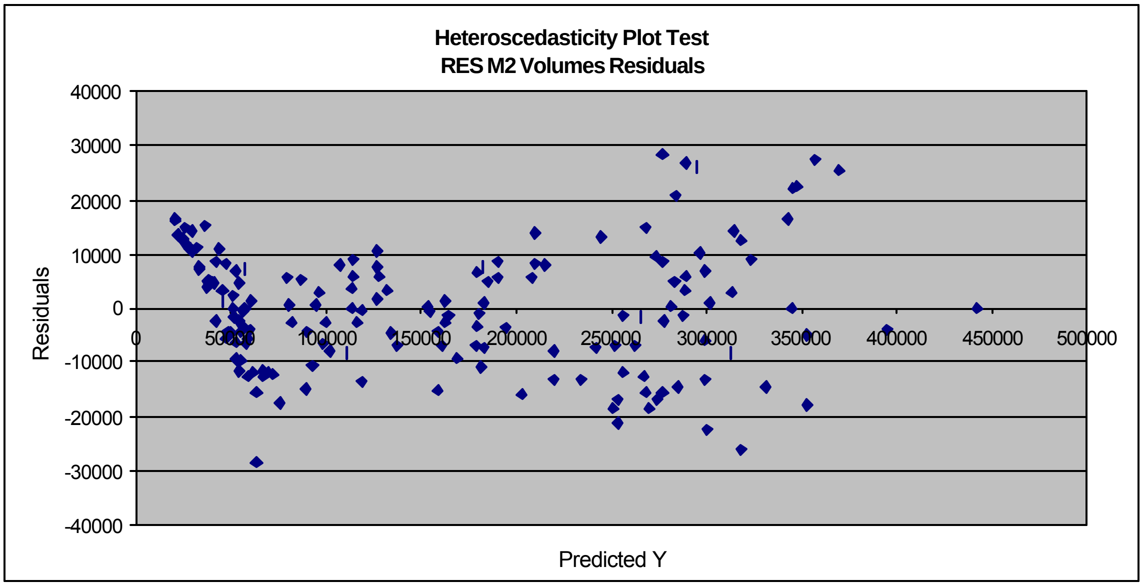
SUMMARY OUTPUT **COM 10 USE**		**HETEROSCEDASTICITY TEST** **"Constant Variance Confirmed"**	
Regression Statistics		*Regression Statistics*	
Adjusted R Square	0.9861	Adjusted R Square	- 0.0070
Standard Error	657.24		
Observations	145.00		*t Stat*
D W Test	1.66	Residuals	- 0.00

	Coefficients	*Standard Error*	*t Stat*
Intercept	- 14,188.05	10,748.54	- 1.32
PRICE(Ex Summer Mnths)	- 1,979.92	881.33	- 2.25
C.F.E.I	16,942.90	10,823.72	1.57
HDD Jan	16.63	0.30	54.96
HDD Feb	16.98	0.35	48.82
HDD Mar	16.89	0.41	41.66
HDD Apr	15.51	0.62	24.84
HDD May	11.52	1.13	10.16
HDD Sept	7.89	1.70	4.64
HDD Oct	15.69	0.76	20.75
HDD Nov	16.89	0.49	34.65
HDD Dec	16.41	0.37	44.38
Dum Use Nov-00	3,675.77	686.55	5.35
Dum Use Dec-00	4,782.40	706.82	6.77

APPENDIX D
HETEROSCEDASTICITY PLOT TEST
CHARTS BY RATE CLASS






Heteroscedasticity Plot Test
RES M2 Volumes Residuals
Residuals
Predicted Y
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30000
20000
10000
0
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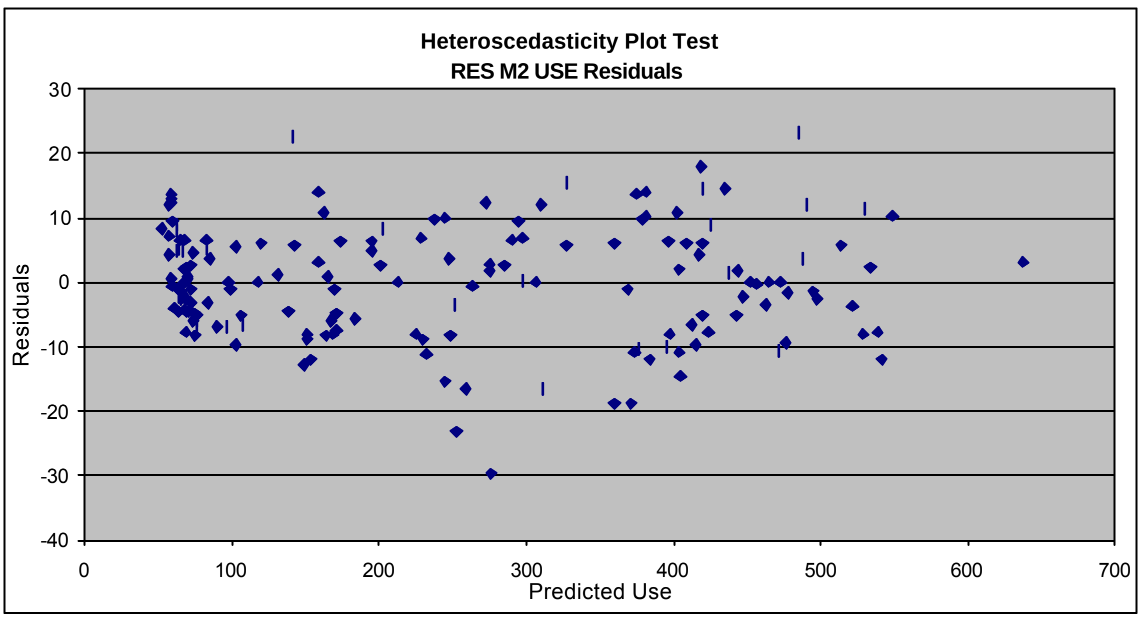
Heteroscedasticity Plot Test
RES M2 USE Residuals
Residuals
Predicted Use
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-10
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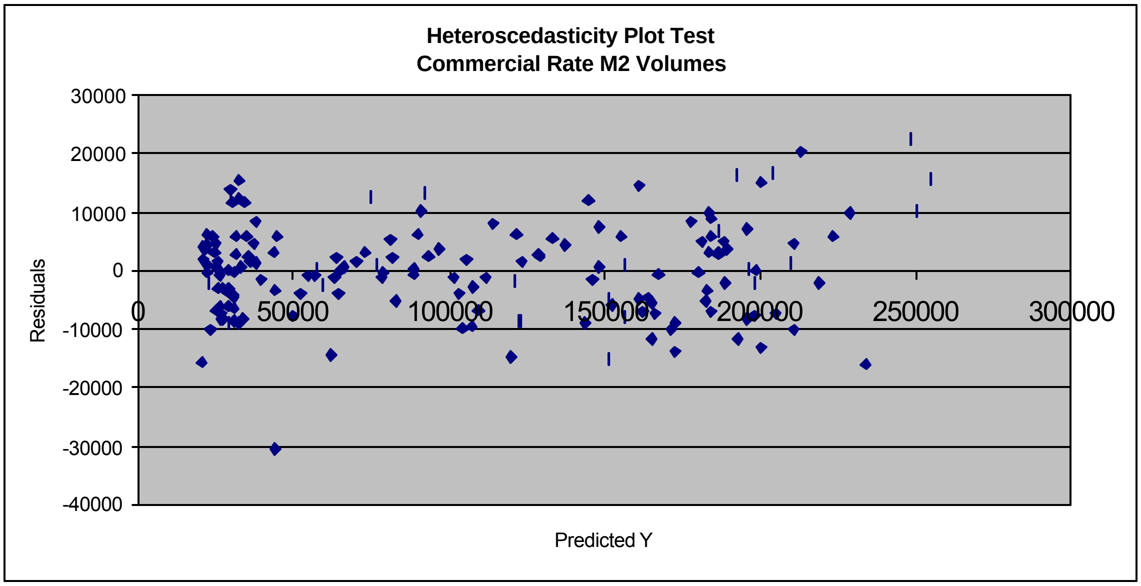
-30
-40
0
100
200
300
400
500
600
700


Heteroscedasticity Plot Test
Commercial Rate M2 Volumes
Residuals
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20000
10000
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-20000
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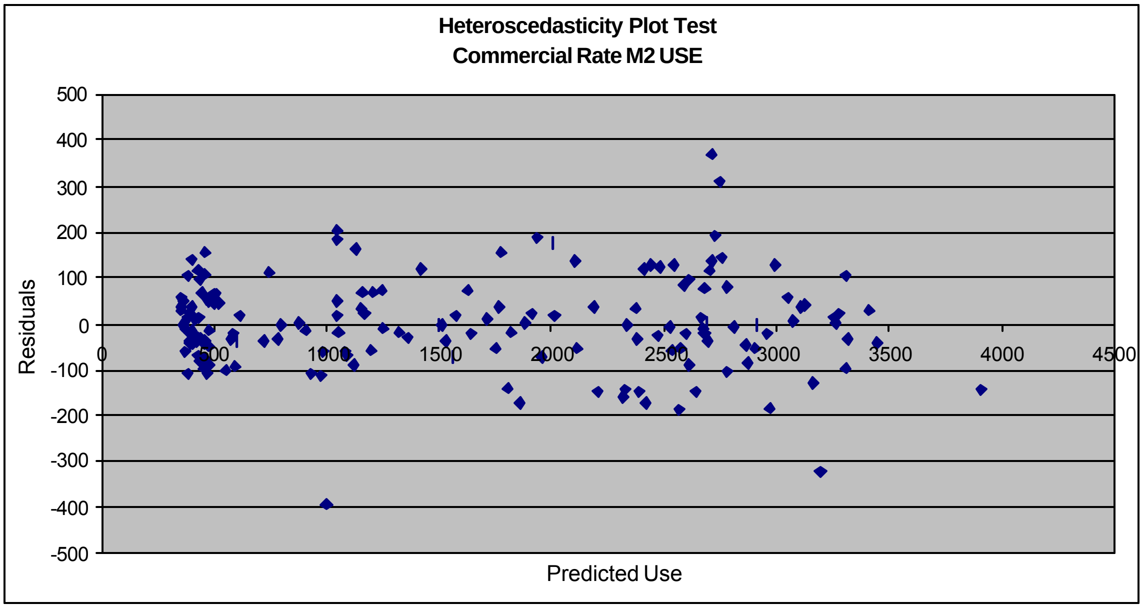
-40000
0
50000
100000
150000
200000
250000
300000
Predicted Y


Heteroscedasticity Plot Test
Commercial Rate M2 USE
Residuals
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300
200
100
0
-100
-200
-300
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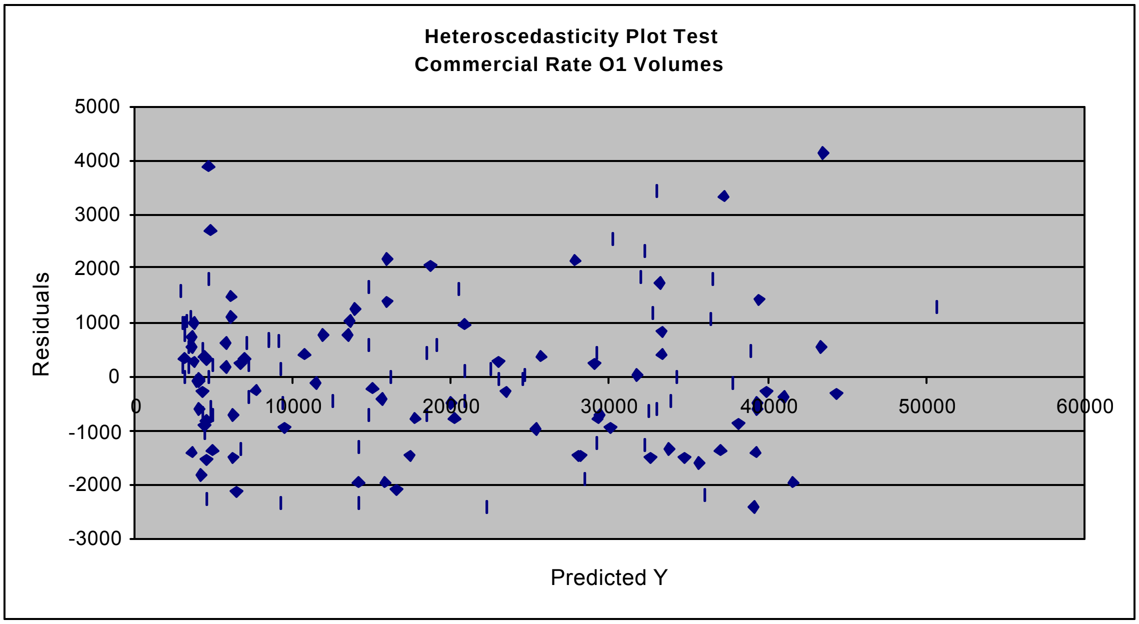
-500
0
500
1000
1500
2000
2500
3000
3500
4000
4500
Predicted Use


Heteroscedasticity Plot Test
Commercial Rate O1 Volumes
Residuals
Predicted Y
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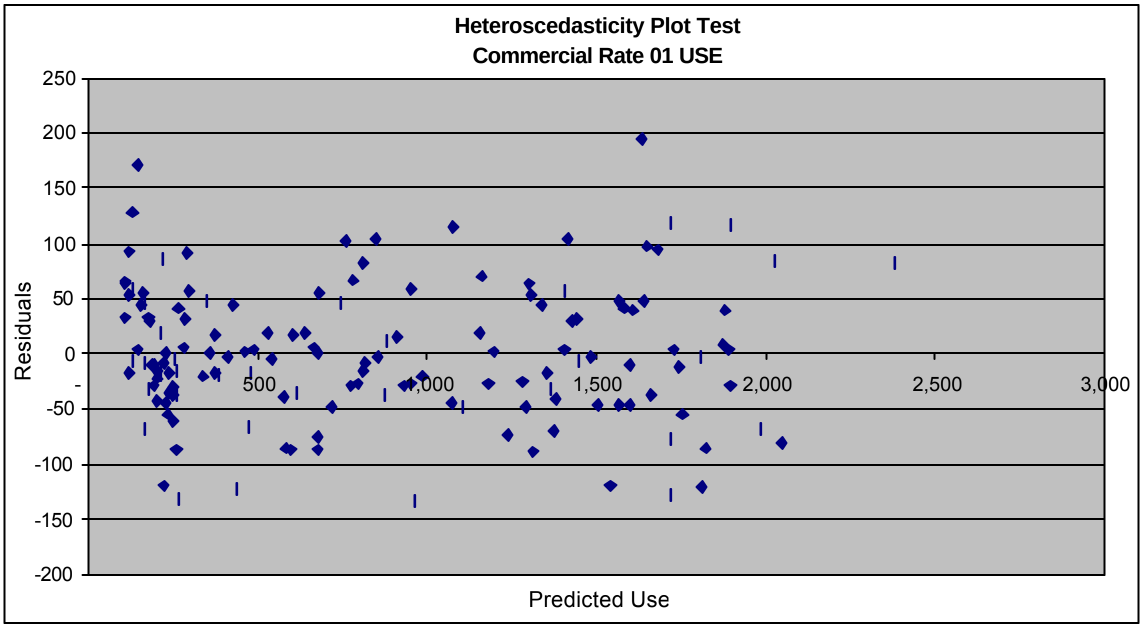
Heteroscedasticity Plot Test
Commercial Rate 01 USE
Residuals
Predicted Use
250
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150
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50
0
-50
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-200
500
1,000
1,500
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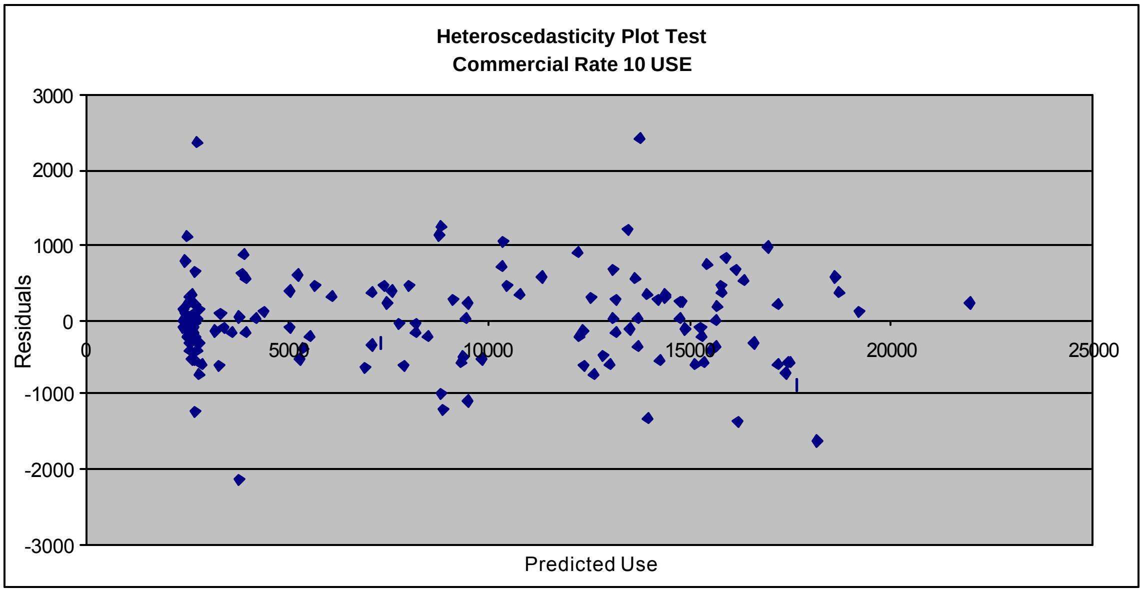
3,000


Heteroscedasticity Plot Test
Commercial Rate 10 USE
Residuals
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2000
1000
0
-1000
-2000
-3000
0
5000
10000
15000
20000
25000
Predicted Use

APPENDIX E
DEMAND FORECAST METHODOLOGY
(SEE NEXT PAGE)

uniongas
A Duke Energy Company

Demand Forecast Methodology

General Service Markets

Rates M2, 01 & Banner 10

May 2004

Table of Contents

1. Introduction:

This report documents the methodology used to prepare the total throughput volumes demand forecast for the general service market served by the following rate classes: Rate M2, Rate 01 & Banner Rate 10. These three rate classes are also classified according to residential, commercial and industrial market sectors, also referred to as customer service classes.

This document does not review either the forecast assumptions or the forecast estimates[1].

The contract rate demand forecast for large volume commercial and industrial accounts served by Union Gas Rates M4. M5, M6, M7, M9, T-1, T-3 20, 25/30, and 100 are prepared by a different methodology and process.

The general service demand forecast provides the basic planning information used to prepare annual corporate budgets, regulatory evidence and capacity management planning related activities. The demand forecast horizon is four years long and includes a bridge year, a budget year, and a rate case test year which could be the budget year or post budget year depending on circumstances.

The demand forecast provides the customer and consumption data needed to prepare the revenue forecast.

The demand forecast uses both internal and external information sources.

The customer billing system and the financial reporting system provides internal information in the form of monthly customer statistics pertaining to the number of customers, the actual total throughput consumption, and the average use per customer consumption for each service and rate class, e.g. residential rate M2. Calendar month consumption data is used; the billing cycle reported information has been adjusted for unbilled consumption estimates. These customer statistics have been compiled in a demand forecast data base with data starting in January 1990. Union Gas rate schedules are also used in preparing monthly retail energy gas price information. Results from Union Gas residential market gas appliance penetration surveys are also considered.

External information related to housing start forecasts, North American economic growth and conditions as measured by the real gross domestic product, light fuel oil prices and trends in the commercial sector are used in the preparation of the demand forecast. Forecasts from the Canada Mortgage and Housing Corporation, Consensus Economics, external economic service consultants and energy price journals are referenced.

2. Econometric Demand Forecast Variables:

Economic demand and consumer behaviour principles suggest that the demand variables selected and contained in the econometric demand equations need to account for several factors.

Seasonality: Any seasonality that is present in the consumption data needs to be explainable. The total monthly heating degree-day weather data accounts for the seasonality.

Trends: Any increasing or declining trend that is present in the consumption data needs to be explained. The energy efficiency trend variable in the residential market explains the declining usage over time and reflects the energy efficiency choices and behaviours of energy consumers. The commercial market segmentation & efficiency trend variable accounts for the declining usage present in the commercial market. Total customer

[1] A forecast assumption indicates the future direction or level of the demand variable, e.g. the number of new customers being added each year ; forecast estimates indicate the result of the forecast, e.g. residential rate M2 NAC estimate of 2,627 cubic metres per year.

growth in the industrial market accounts for the increasing total throughput volumes observed over the estimation period.

Economic Behaviour: Changes in retail natural gas energy prices affect consumption in the residential and commercial markets, and changes in relative prices between natural gas and light fuel oil affect total throughput volumes in the industrial market. As well changes in North American gross domestic product affect total throughput volumes in the industrial market as the provincial economy is well integrated with the larger economy especially via the automotive manufacturing industry.

The criteria used to select the demand variables are important as the econometric estimates of the average consumption per customer are a key component of the demand forecast. There are several criteria for selecting demand data.

The demand variables must be available according to a monthly format and span a fairly long period; 1990 to present in this instance. The monthly data requirement arises from both the seasonality that is present in the demand data and the ultimate client need for the forecast information which is monthly in nature. Monthly data can be a limiting factor in selecting the demand variable data.

The demand variables must be relevant and founded on economic behaviour and energy demand principles; demand theory suggests that weather and retail energy prices are two key demand drivers to consider. Correlations of energy demand to other data that possess a seasonal characteristic that is not related to natural gas energy demand in Ontario, e.g. beer consumption in Australia, is not sound or reasonable.

The data should be ideally franchise area or provincial level detail specific, with the notable exception for the industrial market where North American data can be used. This geographic criterion can also limit the data selection.

The demand data should be public and obtained from reputable sources, e.g. Statistics Canada, external economic services consultants, and should be reproducible.

The demand variables ideally should be statistically significant at the 95 percent level, although lower levels of significance as explained below may be accepted. A student's t test is used to examine the statistical significance of the demand variable in the regression equation.

3. Actual & Normal Weather:

The weather factor is the key demand forecast variable in the econometric analysis. The demand equations and the associated demand coefficients that are estimated are based on actual weather data. Weather is measured by total monthly heating degree-days (HDD) below 18 degrees Celsius. Historic monthly weather data for the southern and northern franchise areas has been compiled since the mid 1960's.

3.1. Actual Weather

Actual monthly weather time series data is used in the estimation of the econometric demand equations. The actual weather data is specified in the regression analysis as a nine month matrix where each heating season month, September through May, is a separate weather variable. For example January HDD is a time series demand variable where all the January months between the years 1990 and 2003 possess as a value the actual observed total heating degree-days during the month and zero values for all other data in the present time series. The other heating season months are set up in similar fashion. **[See Appendix 3.1]**

This weather matrix approach enables a separate weather coefficient to be estimated for each heating season month and this recognizes that consumer behaviour differs between the shoulder months and high heating seasons. The summer months of June through August were identified by previous statistical analysis as being non weather related and represent only base loads. In the industrial equation the time series are quarterly as a result of the GDP data, and the weather demand variable includes the first, second and fourth quarters where the second quarter excludes the month of June.

3.2. Normal Weather

The demand forecast estimates are based upon an assumption of normal weather occurring over the forecast horizon. Normal weather conditions are defined separately for the southern and northern franchise areas; as well, consolidated total company weather normal is established for the industrial demand equation.

Normal weather is defined as a blend of two estimated normals following a decision made by the Ontario Energy Board in April 2004: the blend incorporates a thirty year average normal estimate and an estimate obtained from the 20 year declining trend methodology that Union Gas developed in 2002 and has used in the preparation of the 2002 through 2004 budgets.

The weather normal blend assumes a ratio of 70:30 between the thirty year average normal estimate and the 20 year declining trend estimate for the years 2004 and 2005. The blend drops to a ratio of 60:40 in 2006 and 2007.

The thirty year average is based on monthly weather data spanning the 1974 to 2003 period. Averages are calculated for each month and then summed to yield the annual estimate.

The 20 year declining trend is based on weather data spanning the 1984 to 2003 period. A linear trend in the annual weather data is established by regression analysis; this trend is projected forward. The monthly forecast estimates are obtained from the annual forecast weather normal estimates by applying historic percent distributions for each month. These percent distributions are the average percent shares for the past twenty years.

Historic weather normals are also used to identify past cold and warm years as well as provide a standard weather condition for energy growth analyses of past and future consumption.

The actual weather and forecast normal estimates are shown in **[appendix 3.2]**.

4. Environment Scan:

The environment scan is a forecast assumption document that states expectations regarding key demand factors such as: total housing starts, retail energy prices, alternate fuel prices, real economic growth in Canada and the United States, mortgage interest rates, provincial unemployment rates and service sector employment growth. Sources include: Statistics Canada, Canada Mortgage and Housing Corporation (CMHC), Consensus Economics, The Centre for Spatial Economics (C4SE), Global Insight.

Housing start estimates and mortgage rate forecasts are directly used in the preparation of the customer attachment forecasts. In addition Canadian and U.S. real GDP growth rate forecasts are used to prepare the economic activity variable used in the light industrial demand equation. Retail natural gas and light fuel oil prices at April 2004 are used to prepare the energy price variables used in the regression analysis. The other economic indicators contained in the environment scan are considered in preparing the marketing and DSM plans and are also used for other planning activities within Union Gas, e.g. inflation rates for budgeting purposes.

The environment scan is prepared by Market Knowledge early in the year and updated in September.

The environment scan used in the preparation of the 2005 budget demand forecast is presented in **[appendix 4]**

5. Customer Attachment & Total Customer Forecast:

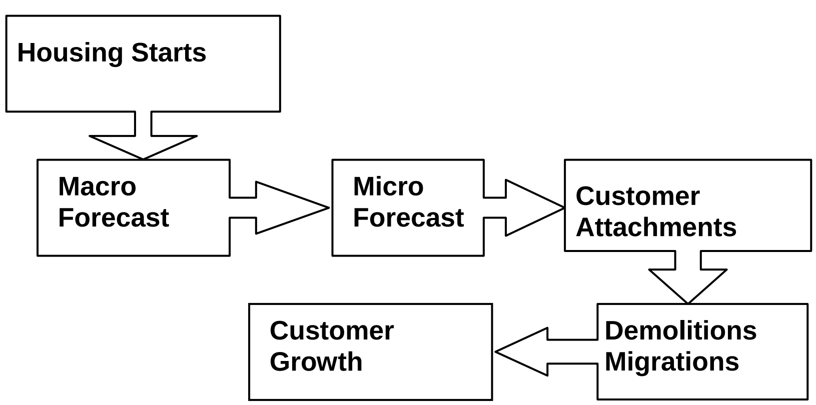
The total customer forecast estimates are obtained primarily from the customer attachment forecast estimates.

The customer attachment estimates are based on a macro analysis and a micro regional based assessment. The customer attachment estimates are gross new customer additions.

The macro analysis translates provincial housing start estimates obtained from several external housing start analysts (CMHC, the Chartered Banks, Consensus Economics, etc.) into a Union Gas franchise housing start estimate. Macro commercial and light industrial customer attachments are also provided. These commercial and industrial customer growth estimates are based on historic residential to commercial and industrial to commercial customer ratios. These annual customer growth estimates do not include any conversion market related customer attachments. This macro analysis is prepared by Market Knowledge for Channel Management.

Channel Management reviews the estimates obtained from the macro analysis and prepares the micro regional based estimates that include the conversion market related customer attachments. The micro regional based estimates become the recommended customer attachment forecast which is reviewed for approval by executive management.

The total customer forecast recognizes that demolitions, customer losses and rate class migration or classification related changes occur; the latter pertain mainly to commercial and industrial customers. These demolitions and other customer loses are subtracted from the gross customer attachment estimates to yield the net customer growth levels.



Monthly customer growth estimates are obtained from the annual estimates by applying historic percent distributions for each service and rate class.

The monthly customer growth estimates for each service and rate class are applied to the most recent historic December total customer level to yield the forecast total customer levels. For example December 2003 was used in preparing the 2005 demand forecast.

The customer attachment and total customer forecast is tabled in **[appendix 5.1 & 5.2]**.

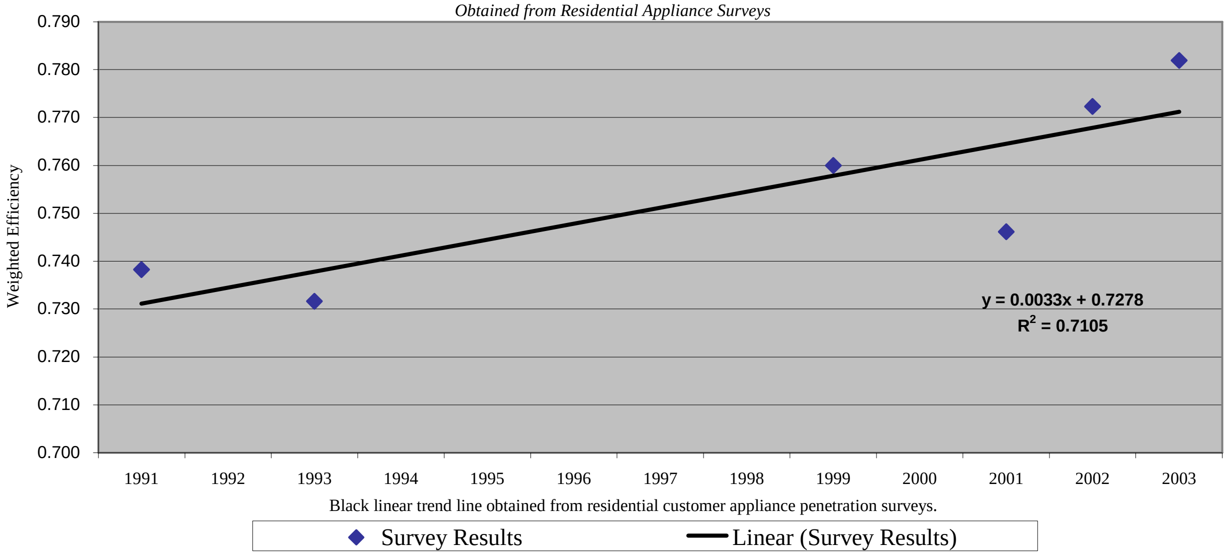
6. Residential Energy Efficiency:

A declining trend is present in the average consumption of a residential customer. A linear trend variable is created and used in the residential use equation regression; this trend variable is established from analysis of furnace type penetration data obtained from Union Gas appliance surveys since 1991. This data is used to establish a weighted furnace efficiency level. Weighted furnace efficiency is determined by multiplying the furnace type market shares by the recognized furnace efficiencies: conventional furnace 60% AFUE, mid efficient furnace 80% AFUE and high efficiency furnace 95% AFUE.

Non linear trends were examined but proved to be statistically inferior to a linear trend according to regression R square results which indicate degrees of fit.

The chart below indicates the weighted efficiency trend which is projected forward to obtain the forecast assumption for this variable. A 71% R-square was obtained.

Chart A
Residential Aggregate Furnace Energy Efficiency
Obtained from Residential Appliance Surveys



Black linear trend line obtained from residential customer appliance penetration surveys.

7. Commercial Market Segmentation:

The use equations in the commercial market demand equations contain a demand variable that represents the changing composition of the commercial market. This trend variable is developed from a commercial market segment analysis that is described below.

The trend variable was derived using the results of the past four years of data created by the model. The following is a discussion of the model and the variables used.

7.1. Commercial Segmentation Model – A Discussion

The model has been designed to be rebased each year using actual consumption data from the billing system. The 2005 Demand Forecast version used actual volumes and customers counts pulled from the customer database for 2003.

Consumption and customer counts are extracted from the billing system using a Discoverer query. The data is then pulled together to classify the data in to the following segments.

7.1.1. Commercial Segments

- Office
- Elementary/Secondary School
- Health Service
- Retail
- Warehouse/Wholesale
- College/University
- Restaurant
- Recreation
- Hotel/Motel
- Religious
- Multi-residential
- Other

Each of the segments is made up of several different dwelling types **[see Appendix 7.1]**, these are compiled together using the monthly consumption data, which is then weather normalized. The annualized data for consumption and dwelling counts are entered in to the model for the base year. Currently we do not split the data into Northern and Southern franchise areas, for analysis, we compile the statistics for the entire franchise area.

7.2. Fuel Shares

The model makes certain assumptions on penetration and use; these assumptions come from outside consultants' reports that have not been updated since the model's creation.

7.2.1. Fuel Shares

	FUEL SHARE EXISTING STOCK			FUEL SHARE NEW STOCK		
	Space Heating	**Water Heating**	**Other**	**Space Heating**	**Water Heating**	**Other**
Office	88%	50%	100%	90%	50%	100%
Elementary/Secondary School	94%	75%	100%	95%	75%	100%
Health Service	94%	94%	100%	95%	95%	100%
Retail	88%	50%	100%	90%	50%	100%
Warehouse/Wholesale	80%	50%	100%	80%	50%	100%
College/University	94%	94%	100%	95%	95%	100%
Restaurant	96%	75%	100%	97%	80%	100%
Recreation	90%	75%	100%	92%	80%	100%
Hotel/Motel	91%	91%	100%	92%	92%	100%
Religious	90%	75%	100%	92%	80%	100%
Multi-residential	91%	60%	100%	92%	80%	100%
Other	80%	50%	100%	80%	50%	100%

7.3. Floor Space

The model calculates energy usage based on floor space, the model assumes specific square footage based on external reports provided in 2002. The current assumptions for floor space per dwelling are as follows:

COMMERCIAL SEGMENT	**SQUARE FOOTAGE per dwelling**
Office	6,000
Elementary/Secondary School	30,000
Health Service	22,500
Retail	5,000
Warehouse/Wholesale	25,000
College/University	150,000
Restaurant	4,000
Recreation	25,000
Hotel/Motel	17,500
Religious	5,000
Multi-residential	41,400
Other	5,000
Total (Average)	**8,500**

7.4. Growth and Decay

The model uses assumptions on growth and decay rates, which the model designer derived from external sources, Energy use indices that are derived from Natural Resources Canada and other studies are used to calculate the use based on the total square footage of the segment. The model calculates the annual consumption by sector for the forecast period.

The following table can be also be found in the **[appendix 7.4]**

Assumptions used for growth, decay & vacancy			
	(percentage per year)		
	Floor Space Growth rates	**Floor Space Decay Rates**	**Vacancy Rates**
All segments (except Multi Res)	0.25%	0.10%	5.00%
Multi-residential	0.25%	0.10%	2.70%

7.5. Energy Use Model

The general form for the equation used for the commercial sector energy model is as follows:

Energy Use = ƒ (A×B×C×D),

Where, A=Activity variable (floor space)
B=Fuel share
C=Energy Technology Intensity
D=Usage

The Activity variable – A – comes from our Union's segment research and industry information. For the model, C and D are combined to create an energy intensity (EI) or end-use intensity (EUI) – **[See Appendix 7.5]**. Fuel shares – B – comes from information obtained by Union's own research. Once the model is populated, a calibration exercise may be performed if it is deemed necessary. This exercise allows the user to tailor the model for changes in any of the variables, such as changes in floor space of a sector, change in growth patterns or changes in use.

The following has been extracted form the current model and shows relative impacts on overall energy use of various changes in our inputs.

Volumes in 10^3m^3	Model 2004	1% Customer Change	1% Fuel Share
Office	420,984	4,210	8,378
Elementary/Secondary School	219,525	2,195	2,195
Health Service	89,369	894	868
Retail	182,789	1,828	1,806
Warehouse/Wholesale	96,291	963	963
College/University	65,406	654	631
Restaurant	82,973	830	784
Recreation	78,441	784	784
Hotel/Motel	25,180	252	247
Religious	28,803	288	288
Multi-residential	242,762	2,428	2,104
Other	276,396	2,764	2,641
Total	**1,808,918**	**18,089**	**21,689**

Each year when the data is extracted from the billing system there are checks that must be run against the data. One of the key items is customer count; if there is an unexpected result, the reason for its occurrence is investigated. This may mean re-pulling the data and/or contacting the Banner group to determine if there may have been changes to the system that may have accounted for this. If this does not resolve the issue, we try to determine if something has happened in the affected sectors that may be driving change.

The model uses a historical growth rates for fuel share and floor space applied across all the segments. The model may be changed to reflect changes in growth across the various segments. Demolitions and vacancies are also accounted for within the model and may be changed as needed.

Floor space Growth Rate used is 0.25% per year Decay rate used is 0.10%. The Assumed vacancy rate is 5% with the exception of Multi-residential at 2.7%

Fuel Share Growth Rate - % Existing is 0.25% New 0.50%

EUI Improvement - % - Existing is 0.10% New 1.0%

Overall percentage growth built into the model

Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Percentage Growth	0.264%	0.035%	0.035%	0.035%	0.035%	0.035%

The largest sectors in terms numbers, floor space and total volumes are really office and retail. The Commercial “Other” group tends to be a group of unclassified businesses that at the time of being entered in to the billing system were just lumped into the generic category. Some work has been completed in the clean up of these records.

BASE YEAR: 2003

COMMERCIAL SEGMENT	**REPORTED GAS USE (10^3m^3)**	**NUMBER OF BUILDINGS**	**TOTAL FLOORSPACE (SQ. FT)**	**AVERAGE ANNUAL USE (m^3/bldg)**
Office	417,948	34,342	206,052,000	12,170
Multi-residential	278,568	2,600	107,640,000	107,141
Other	268,915	19,839	99,195,000	13,555
Retail	179,890	18,023	90,115,000	9,981
Elementary/Secondary School	167,618	2,457	73,710,000	68,221
Health Service	85,528	910	20,475,000	93,986
Restaurant	75,489	4,651	18,604,000	16,231
Warehouse/Wholesale	69,578	3,283	82,075,000	21,193
Recreation	65,886	1,227	30,675,000	53,697
Religious	39,944	2,623	13,115,000	15,229
Hotel/Motel	21,283	602	10,535,000	35,354
College/University	13,251	124	18,600,000	106,860
Total	**1,683,900**	**90,681**	**770,791,000**	**18,569**

To summarize the commercial segmentation model provides us with a tool to predict the various dynamics of our commercial market. The model is easily adaptable to changes within our markets and is an invaluable tool for analyzing the commercial segments.

The commercial segment model predicts total volumes and total use per customer. The total commercial use per customer estimate is then converted into the trend index variable that represents the changing commercial segmentation and energy efficiency characteristics present in the market. The Model’s usefulness will improve as additional years’ of data are accumulated.

8. Retail Energy Prices:

The retail natural gas prices used in the regression analyses were constructed from the monthly actual use per customer statistics for each customer service & rate class and the appropriate delivery, commodity and transportation rate schedules for the period January 1990 to December 2003.

The consumption of an average system sales customer was assumed in the creation of the burner-tip unit prices; this average consumption was applied to the delivery consumption rate blocks in the rate schedules to derive the average unit price. Retail price information that direct purchase customers pay is spotty and the market share of each retail energy marketer is not available to create a weighted market retail price due to code of conduct ethics.

Retail energy prices primarily change when the more volatile commodity price changes.

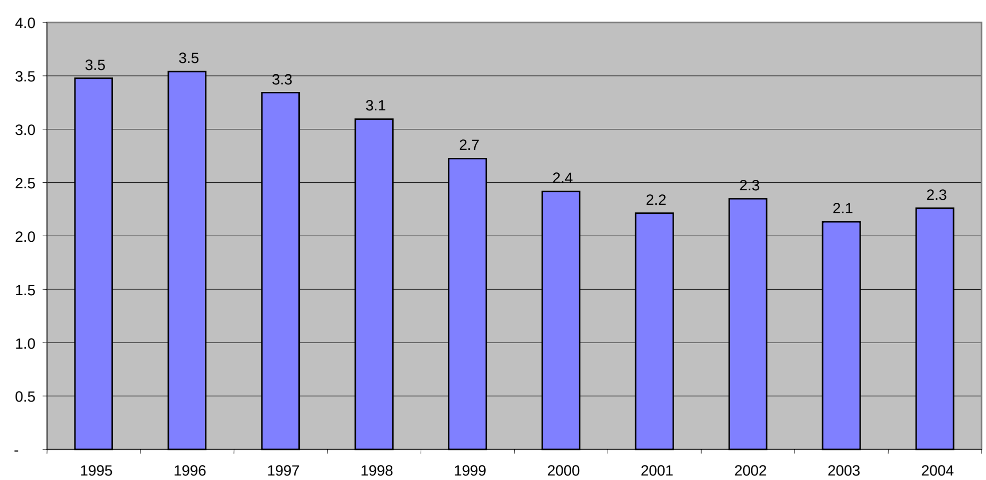
Light fuel oil prices reported for the London, Ontario wholesale market are used in the estimation of the industrial demand equation.

Electric power retail prices were not analyzed for the following two reasons:

Electric distribution company retail power prices for the 90 odd electric power companies located throughout the Union Gas franchise area are not available on a monthly basis. Residential average use statistics for electric power are not public and easily made available. Electric power usage in the commercial segment would vary widely by commercial segment, and commercial segment consumption data is limited for gas consumption and non existent for electricity consumption.

Over the 1990 to 2003 period electricity prices were frozen in Ontario; price comparisons indicate that electricity is not competitive with natural gas as the price ratio between electricity and natural gas has ranged from the 3.0 to 2.0 levels. Any relative price demand price variable in the regression equation would essentially reflect the gas price variation.

Electricity to Natural Gas
Residential Retail Price Ratio



9. Econometric Equations:

The estimation of econometric demand equations for forecasting purposes is based upon econometric practices and principles. Economic theory and statistical methods are the basis of econometrics. Energy forecasting is applied econometrics. Forecasters are challenged by data limitations due to the availability and appropriateness of the information, the cost of obtaining the information, and the complexity in creating the appropriate information in certain instances, e.g. weighted market share retail energy prices.

Forecasters seek to improve their forecast equations by enhancing the equation specifications which may involve lagging variables, pooling data, adding newly obtained information, and incorporating knowledge obtained from forecasting journals and attendance at forecasting conferences to name a few examples.

10. NAC Forecast:

The normalized average consumption (NAC) forecast estimates for the general service rate and service class customers are a major component of the total throughput volumes demand forecast. The NAC forecast is a key determinant to the rate of growth present in the demand forecast.

The NAC forecast estimates are obtained by summing the results of three separate analyses. These three analyses are: the econometric NAC forecast estimates, the marketing plan NAC impact estimates and the DSM plan NAC impacts. These are described below.

10.1. DSM Plan & Energy Efficiency Trend

As described in the Use Equation section below, the historic Union Gas DSM plans need to be recognized in the regression analysis. The energy efficiency trend variable that is used in the use equations should not contain the impact of the past DSM plans.

Double counting the DSM plan impact in a going forward analysis is the issue; the historic energy efficiency trend that is estimated by the regression analysis should only reflect the condition where there is no DSM plan in place, as the new incremental DSM plan impacts is overlaid. This issue affects only the residential and commercial use equations and is not present with any of the volume equations.

This double-counting issue is resolved by restating the reported consumption statistics that are used to estimate the energy efficiency coefficient present in the use equation. Two regressions are undertaken; one with the actual reported statistics and one with the restated statistics. The restatement makes an account for the total consumption impact of past DSM plans. Audited annual DSM plan consumption statistics are used to restate the actual consumption data; monthly allocation is based on the seasonality present in the reported actual statistics. The restatement affects only the energy efficiency coefficient. The remaining coefficients contained in the use equation are based on the actual reported statistics.

11. Econometric NAC Forecast Estimates:

Econometric normalized average consumption (NAC) forecast estimates are determined for each service and rate class: residential Rate M2 and 01, commercial Rate M2, 01 & 10, and industrial Rate M2 and 10. The forecast estimates are referred to as normalized average consumption because they are based on normal weather assumptions as discussed earlier in the weather normal section above.

11.1. Statistical Estimation & Rigour

The econometric estimation process that is applied in preparing the NAC forecast estimates follow generally accepted energy demand forecasting methods. The independent demand variables included in estimated demand equations are variables that are conceptually well recognized as drivers for energy consumption, e.g. weather, retail energy prices, etc.

The estimated demand equation are selected on the basis of the conventional tests: Regression R Square, F and t tests, and Mean Absolute Percent Error (MAPE) for the equation fit, the Durbin Watson (DW) & Durbin H (DH) tests for auto correlation, and the Chow test for the presence of heteroskedasticity. Graphic examination is also undertaken.

A 95 percent confidential level is ideally the first screen or test level that one considers for determining the statistical significance of a demand variable.

For the majority of the 136 demand variables tested that are contained in the 11 demand equations, this 95 percent level is met as 127 demand variables had t test scores above the 95 percent confidence level. In nine instances a lower confidence level was considered and this is noted in the table below. The column titled P-value indicates the inverse of the confidence level. The percent level is obtained if the P-value is subtracted from 1.

The table shows that in three instances a 90 percent level indicates significance (Res M2 Price, Comm M2 Volume lagged and Ind Volume GDP); in 5 cases a level of 80 percent indicates significance (Res M2 Price, Comm M2 Volume lagged, Ind Volume GDP, Com 10 Commercial Index, Ind Volume Price Ratio).

Rate Class	Equation	Variable	*P-value*
Res M2	Volume Equation	Price	0.07
Com 01	Volume Equation	Volume Lagged	0.49
Com 01	Volume Equation	Price	0.53
Com 01	Use Equation	Price	0.26
Com 10	Use Equation	Commercial Index	0.12
Com M2	Volume Equation	Volume Lagged	0.08
Com M2	Volume Equation	Price	0.57
Ind	Volume Equation	GDP	0.06
Ind	Volume Equation	Price Ratio	0.19

A lower confidence level is acceptable if the dependent variable is widely recognized in the energy demand forecast community as a key demand forecast variable, e.g. retail energy prices. Furthermore, if the estimated demand relationship is correct, e.g. an inverse relationship between price and demand, and the estimated demand elasticity is within the expected range as indicated by a research of external literature then the variable can be included. If the inclusion of the variable improves the historic accuracy of the predicted estimate or does not materially affect the forecast estimate then also the inclusion of the variable is not a concern. Materiality defined as being within the standard error or mean absolute percent error range. If the inclusion of the variable eliminates an auto correlation issue that is present in the equation without the variable then the inclusion of the variable is a sound and reasonable forecasting technique.

For example: The price ratio variable in the industrial volume equation is significant at the 81 percent confidence level. Excluding the price ratio variable from the industrial volume equation yields a demand equation whose residuals are positively correlated, whereas the demand forecast equation that incorporates the price ratio variable is not auto correlated. The excluded variable equation possesses both a larger standard error and a larger mean absolute percent error for the predicted annual estimate. The t statistics for the remaining variables in the excluded variable equation all pass the 95 percent confidence test. The total volume estimate for 2005 obtained from the demand equation that excludes the price ratio variable is 0.7 percent higher than the estimate obtained from the demand forecast equation.

The presence of autocorrelation in an initial demand equation is remedied by introducing a lagged dependent variable in the equation and using the Durbin H statistic to test for autocorrelation.

11.2. Two Equation Approach

Specifying the demand equation as either an “average use per customer” equation or a “total volume” equation follows a conventional approach in econometric estimation. Either approach can yield strong and statistically significant demand equations. Both equations have their merits; the use equation identifies the trend present in the consumption data and the volume equation better identifies the demand-price relationship. And both approaches share common demand variables such as weather.

For the residential and commercial service classes, Union Gas has found that averaging the estimates obtained from each approach yields an econometric NAC estimate that is more accurate than the results that would be obtained from the individual equations.

The volume and use per customer demand forecast equation approaches are described below.

11.3. Volume Equations

See **[Appendix 11.3]** for Volume Equation Coefficients.

11.3.1. Residential Rate M2 & 01

The volume equation approach is used to estimate NACs in all three service classes.

The process of forecasting demand relies on using historical consumption data and identifying variables that can, at first accurately replicate historical demand patterns. The statistical results reveal the significance of the variables included and the extent to which they are able to predict historical demand. The object being that the models include all the primary drivers of demand and have the capacity to predict future demand with the same accuracy as it predicts historical demand.

Based on 14 years of monthly reported throughput volumes data for each of the rate classes, various drivers which could influence demand were tested using regression analysis to arrive at the final three, which are Number of Customers, Natural Gas Prices and Weather data for the two principal southern and northern franchise areas.

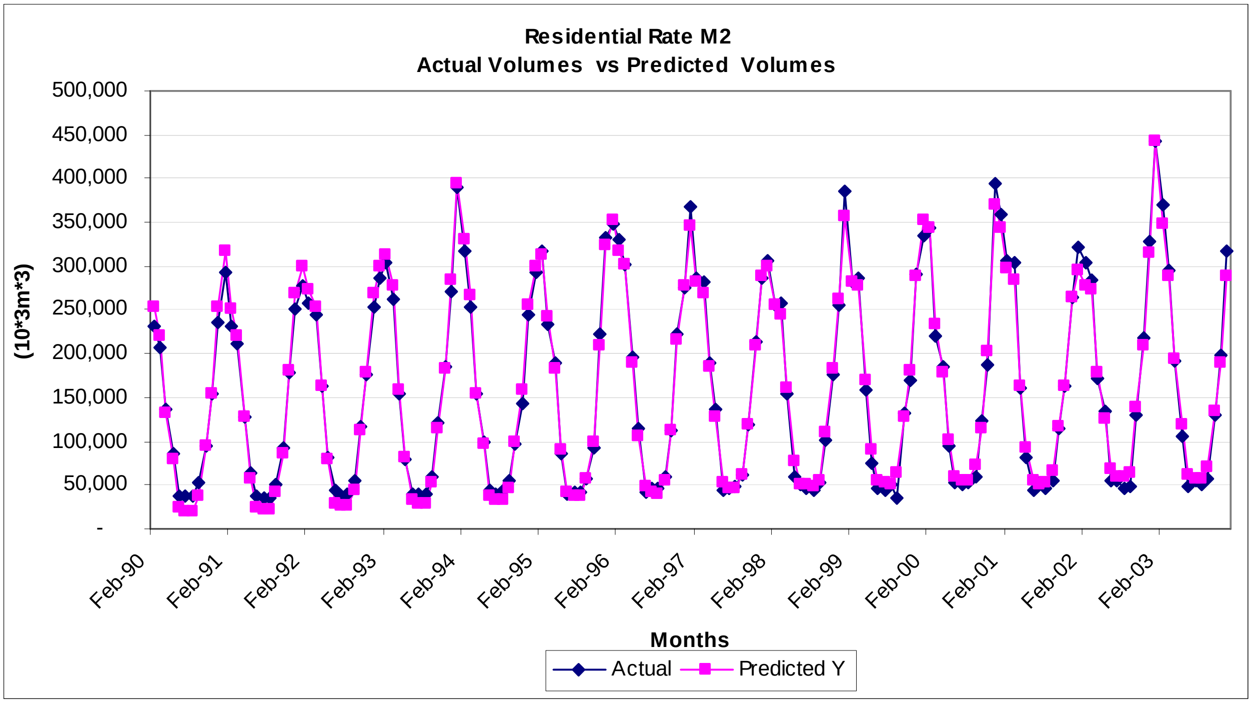
The Volume Equation for the residential market is defined by the relationship, total throughput volumes are a function of number of customers, natural gas prices and weather.

The monthly total number of customers captures the growth over time in throughput volumes. The retail natural gas prices identifies the consumer economic behaviour as the price variable is a retail burner tip price that is determined from the average use per customer statistics for each rate class and the past and current Union Gas delivery, transportation & commodity charge rate schedules. The weather variable, which is the primary driver of demand, is set-up as a matrix that excludes the summer months of June, July and August. Weather accounts for the seasonal patterns contained in the consumption data. Actual monthly weather data for the southern and northern franchise areas is considered.

Total Throughput Volumes= f {Number of Customers, Natural Gas Prices, Weather}

Where:

Number of customers is the total number within the residential service and rate class, e.g. Rate M2.
Natural gas price is the residential retail burner tip unit price that excludes the fixed monthly charge.
Weather measures the total number of heating degree-days during the month.



The historic fit between the actual total consumption and the demand equation's estimated predicted values is shown in the chart above. The mean absolute percent error between the actual consumption and predicted estimates for the total annual throughput volumes is **1.3** percent with a standard deviation of **0.8** percent. This implies that the demand equation has forecast capability of roughly plus or minus **1.6** percent.

The regression results are presented in **[Appendix 11.3.1]**

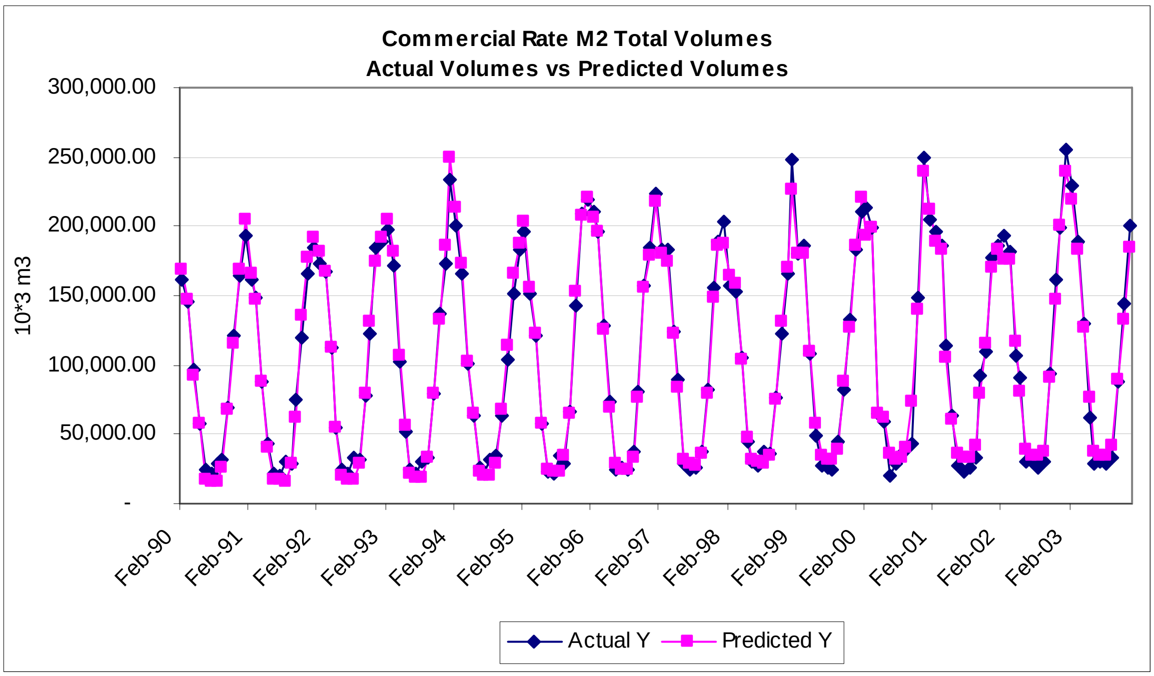
11.3.2. Commercial Rate M2, 01 & 10

The demand variables contained in the volume equation that were found to drive demand in the commercial market are similar to those cited above for the residential market. The only difference being that the total number of customers and the retail unit prices are based on the individual commercial customer rate class statistics. The structure of the volume equation is the same as that used in the residential service class. The volume equation is defined as follows: total throughput volumes are a function of natural gas prices, weather and number of customers.

Total Throughput Volumes= f *{Number of Customers, Natural Gas Prices, Weather}*

Where:

Number of customers is the total number within the commercial service and rate class, e.g. Rate M2. Natural gas price is the commercial retail burner tip unit price that excludes the fixed monthly charge. Weather measures the total number of heating degree-days during the month.



The historic fit between the actual total consumption and the demand equation's estimated predicted values is shown in the chart above. The mean absolute percent error between the actual consumption and predicted estimates for the total annual throughput volumes is **1.5** percent with a standard deviation of **1.1** percent. This implies that the demand equation has forecast capability of roughly plus or minus **2.2** percent.

The regression results are presented in **[Appendix 11.3.2]**

11.3.3. Industrial Rate M2 & 10

The volume equation was the only approach selected for the industrial service class. The volume approach enabled the identification of an economic activity variable in the demand equation. This economic activity variable is based on quarterly changes in North American real gross domestic product (GDP). A relative industrial gas to fuel oil price variable completed the demand equation. Weather identifies the seasonality present in the monthly total consumption data. The total customer variable accounts for the growth over time in the consumption.

A consolidated industrial service class was examined as opposed to three individual rate class equations. The total volumes represent the sum of Rate M2, Banner Rate 10 and CIA Rate 10 customers. Industrial Rate 16 volumes were also included; this interruptible rate class is currently vacant. Inclusion of CIA Rate 10 and industrial Rate 16 customers improved the statistical estimation and this inclusion recognized that there has been migration back and forth over time between Banner and CIA Rate 10 customer classes, as well as with the Rate 16 customer class.

Pooling the industrial rate classes together creates a light industrial sector that correlates with North American GDP, which is not the case if individual and separate service class demand equations were specified. Weaker results were obtained if the volume equation was specified using the individual rate class information, e.g. the industrial rate M2 which represents about 83 percent of the total light industrial volumes, the regression analysis identifies only the weather relationship and the overall regression results are weaker in terms R Square and F statistics. This pooled rate class approach also enables the demand equation to identify a relationship between consumption and comparative energy prices.

The estimated industrial demand equation based on historical quarterly data spanning 1996 to 2003 is the following:

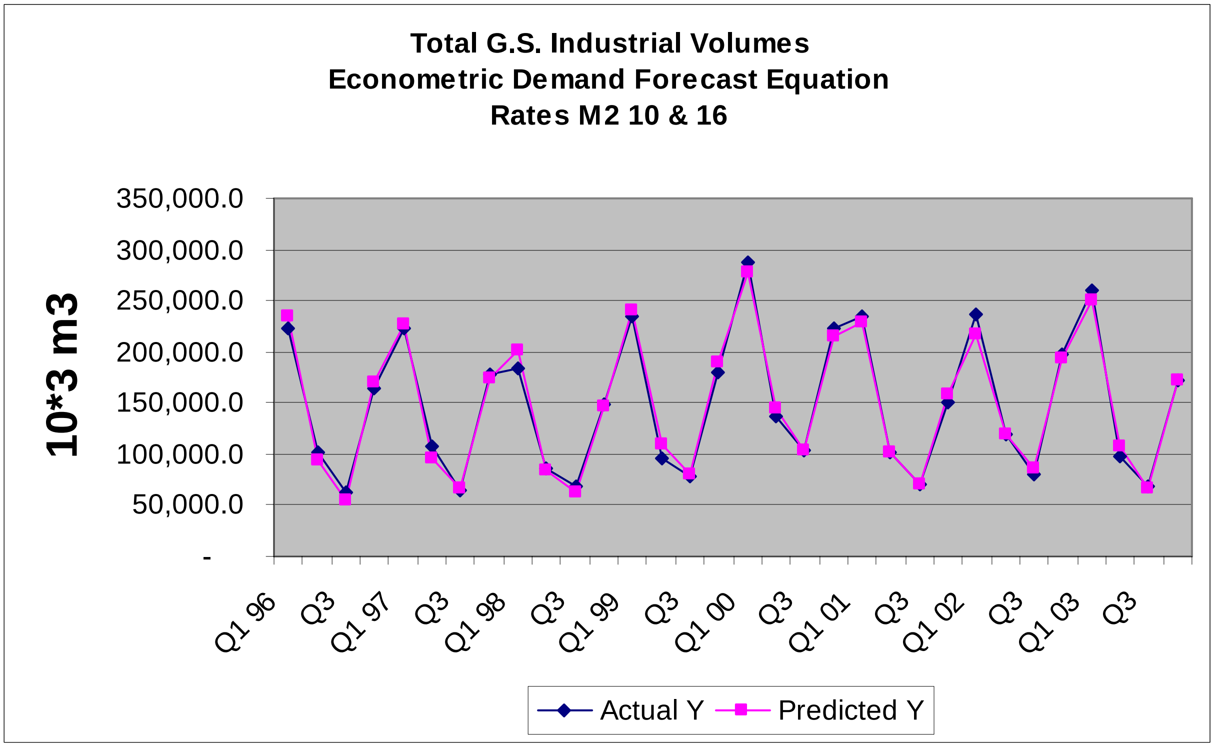
Volumes = f (weather, customers, lagged change in GDP, and the price ratio between natural gas and fuel oil.)

Where:

- Volumes is the consolidated total throughput of industrial Rate M2, 10 and 16 customers
- Weather represents the total heating degree-day weather matrix for nine heating months
- Customers is the consolidated total number of industrial Rate M2, 10 and 16 customers
- Lagged change in GDP is the quarter to quarter real dollar change in gross domestic product
- Price ratio relates the industrial burner tip natural gas unit price and the wholesale light fuel oil No. 2 price at London Ontario.

Consistent price data prior to 1996 was limited and this constrained the analysis.

The historic fit between the actual total consumption and the demand equation's estimated predicted values is shown in the chart below. The mean absolute percent error between the actual consumption and predicted estimates for the total annual throughput volumes is 1.8 percent with a standard deviation of 1.7 percent. This implies that the demand equation has forecast capability of roughly plus or minus 3.5 percent.



The statistical results for industrial volume equation are presented in **[Appendix 11.3.3-1]**.

The total throughput volumes for the industrial Rate M2 service class customers are obtained from the total consolidated volumes equation by means of a subsidiary regression equation that relates industrial Rate M2 volumes to the consolidated volumes. The results for this subsidiary regression are also shown in **[Appendix 11.3.3-2]**.

The total throughput volumes for the industrial Banner Rate 10 service class customers are obtained as a residual once the historic market share of CIA Rate 10 customers of the total consolidated volumes is attributed. CIA Rate 10 customers over the past two years have represented about 13.8 percent of the total consolidated light industrial throughput. The currently are no industrial rate 16 customers and none are expected in the future.

Once the historic predicted estimates and the forecast estimates, for the Rate M2 and Banner Rate 10 industrial volumes are obtained, the actual predicted average use and the forecast NAC estimates are determined by dividing the total volume estimates by the number of industrial customers in each service class.

Note that the volume approach demand specification yields an equation whereby increases in the total number of customers increases the NAC estimate. This seemingly paradoxical result arises from the presence of the other variables in the equation and the large estimated constant value that is part of the equation. The equation infers that over the past new industrial customers were larger than the average customer.

11.4. Use Equations

The use equation approach is used to estimate NACs in the residential and commercial service & rate classes. See **[Appendix 11.4]** for Use Equation Coefficients.

11.4.1. Residential Rate M2 & 01

The residential use equation emerged out of a need to capture the impact that energy efficiency has on overall consumption. As described earlier, a residential trend variable that represents energy efficiency gains was included in the use equation.

The residential use equation is determined from 14 years of monthly reported consumption data starting in January 1990 and finishing in December 2003.

Since reported use per customer data is used in the regression analysis, this implies that all the past DSM plan related efficiency gains are included in this historic consumption data. The incorporation of an efficiency variable in the model causes DSM gains to be counted twice. In order to prevent this, cumulative audited DSM impacts since 1995 were obtained and then added back into the actual reported use per customer statistics.

The use equation for the residential market is defined by the relationship; total use per customer is a function of natural gas prices, residential energy efficiency trend and weather.

Use per Customer= ƒ {Natural Gas Prices, Residential Energy Efficiency, Weather}

Where:
- *Natural Gas Prices* are an average price that is representative of the economic forces driving energy demand
- *Energy Efficiency Trend*, captures the changing mix in appliance type and penetration
- *Weather* represents the total heating degree-day weather matrix for nine heating months.

11.4.2. Commercial Rate M2, 01 & 10

The use equation for the commercial market is similar to the use equation in the residential market as it defines use per customer is a function of natural gas prices, a trend variable representing the changing mix in commercial market segmentation and weather.

Use per Customer= ƒ {Natural Gas Prices, Commercial Segmentation Index, Weather}

Where:
- *Natural Gas Prices* are an average price that is representative of the economic forces driving energy demand
- *Segmentation Index*, captures the changing mix in commercial market segmentation and energy efficiency.
- *Weather* represents the total heating degree-day weather matrix for nine heating months

11.4.3. Industrial Rate M2 & 10.

No use equation is estimated for the light industrial rate class.

The application of a use equation approach for the industrial market is difficult as the energy demand forecaster is confronted with the presence of an increasing trend in the average consumption that does not appear to relate to economic conditions. This conclusion is based on various exploratory regression equations that were undertaken. Identifying the price variable in the use equation, specified as either a single natural gas price variable or as a relative price, was not found to be significant. The use equation approach yielded weaker statistical results (R Square, F and t tests, MAPE) compared to the volume equation approach and therefore this use equation approach was not pursued any further.

12. DSM & Marketing Plan NAC Impacts:

The econometric demand equations do not take account of the incremental impact on total throughput of new Demand Side Management (DSM) and marketing plan programmes. Being new programmes, the actual customer consumption statistics do not reflect these programmes.

New DSM programmes lower total throughput by encouraging increased energy efficiency. New marketing plans encourage customers to consider clean natural gas energy instead of other energy types; these marketing plans marginally increase total throughput.

The Channel Management department provides the total volume estimates associated with these new DSM and marketing programmes. These annual volumes for the pertinent service class are cumulated over the multi-year forecast horizon and then divided by the forecasted total average number of customers in the service class to yield the incremental NAC impact. These are shown in **[Appendix 12].**

A small water heating energy efficiency related impact is also recognized. New water heater standards support this adjustment.

The volume impact of previous DSM plans were taken into account in the estimation of the demand equations following the use equation approach as described earlier in the econometric NAC Forecast Estimates section.

13. Total NAC Forecast

The two tables below summarize the preparation of the NAC Forecast and show the forecast estimates. The first table indicates the process:

NAC Forecast = Econometric Forecast + DSM & Marketing Plan NAC Impacts + Other Adjustments

NAC ESTIMATES & ADJUSTMENTS

YEAR 2004	Res M2	Res 01	Comm M2	Comm 01	Comm 10	Ind M2	Ind 10
Use Equation NAC Estimate (1)	2,748	2763	18,153	8,751	102,625		
Historic DSM NAC Impact	-70	-72	-701	-364	-3,806		
Use NAC Estimate (A)	2,678	2,691	17,452	8,387	98,819		
Volume Equation NAC Estimate (B)	2,646	2,748	17,715	9,215	99,101	85,797	261,926
Average of A & B	2,662	2,720	17,584	8,801	98,960	85,801	261,931
Marketing Plan NAC Impact	12	12	112	112	112		
DSM NAC Impact	-2	-2	-67	-25	-265	-332	-774
Water Heater Standards Eff	-2	-2					
NAC	2,669	2,728	17,629	8,888	98,807	85,469	261,157
FINAL NAC Forecast Estimate	**2,670**	**2,728**	**17,629**	**8,888**	**98,807**	**85,469**	**261,157**

The following table indicates the final annual NAC forecast estimates developed by the forecast methodology and process. Charted illustrations of the NAC forecast are presented in the table below.

BUDGET 2005: TOTAL NAC FORECAST: m3

	Residential Customers		Commercial Customers				Industrial Customers	
	Rate M2	Rate 01	Rate M2	Tobacco M2	Rate 01	Rate 10	Rate M2	Rate 10
2003	2,700	2,819	17,877		9,412	98,675	88,884	282,671
2004	2,669	2,728	17,629	29,895	8,888	98,807	85,469	261,157
2005	2,627	2,677	17,290	29,895	8,647	97,355	88,054	303,146
2006	2,594	2,635	16,972	29,895	8,435	96,125	88,448	299,766
2007	2,570	2,602	16,796	29,895	8,293	95,554	89,165	297,211

14. Direct Purchase Market Estimates:

The direct purchase (DP) market includes customers served by the following delivery service options (DSO): ABC-T service, bundled T service and the new unbundled service option.

The demand forecast estimates for this market are based on two key determinants:

1) The total number of customers by service and rate class for each direct purchase service option is set by the total number reported at a specified time. For the 2005 Demand Forecast the total count at March 2004 set the total direct purchase customer levels. Total customers by direct purchase service option are held constant over the forecast horizon, except for one situation. The total number of ABCT customers decreases by the number of unbundled service customers when that service offering commences, e.g. May 2004. Total unbundled customers remain constant over the forecast period. The assumed constant level of direct purchase customers recognizes the difficult challenge and uncertainty related to forecasting the market share held by direct purchase service suppliers.

2) The NAC forecast estimates for each DP service & rate class is related to the all DSO or aggregate NAC estimates. These aggregate NACs indicate the average consumption of all customers regardless of delivery service option being used. A historic ratio relates the DP NACs to the aggregate NACs. These ratios are based on the most current historic relationship between the aggregate and the DP NACs based on customer billing information and DP customer information as provided by Customer Fulfillment Support Services. In general, the residential ratios are close to one, whereas the commercial and industrial DP NAC ratios show a notable difference between the aggregate NAC and DP NACs.

The northern region is obtained by a residual calculation from the northern rate 01 &10 franchise area after the five other regions have been estimated based on historic volume market share percentages. This provides a reconciliation feature for the very detailed regional volume forecast calculation.

The product of forecast DP customer and NAC estimates derives the DP total demand forecast. The subtraction of the DP customers and total throughput volumes from the aggregate All DSO customer and total throughput volumes forecast yields the system sales forecast of customers and total throughput volumes.

15. Total Throughput Volumes Forecast:

The total throughput volumes forecast is the product of the service class customer and NAC estimates for each month, rate class, delivery service option and region that has been described above. Annual consumption estimates are summations of the monthly estimates.

The total throughput volumes forecasts provide the base gas supply planning information as the throughput forecast identifies total monthly demand by delivery service option for both northern and southern franchise regions; the northern franchise can further be subdivided into six regions that indicate TCPL toll zones and specific single supply source situations, e.g. Sault Sainte Marie.

16. Differences in methodology from Budget 2004 filed Evidence:

The Budget 2005 Demand Forecast methodology very closely follows that of the Budget 2004 Demand Forecast filed evidence. The only notable differences are outlined below:

- All the models in each of the rate classes have been updated to reflect an additional one year of data.
- Some of the assumptions previously used in the Total Throughput Volumes Industrial Model have been replaced with variables which are more significant and far more reflective of the actual relationship. The previous equation was defined by the relationship: *Volumes= ƒ {Number of Customers, Gas Prices, Heavy Fuel Oil Prices, Weather, Efficiency Trend}.*
- The NAC Reasonability Test is no longer a part of the methodology in determining the Budget 2005 Demand Forecast.

16.1. NAC Reasonability Test As Used in Budget 2004

16.1.1. NAC Reasonability Test

The January to March period represents a significant portion of the total annual consumption, almost half of the annual consumption in certain rate-service classes. The table below shows these proportions for each service and rate class. Examining the trends present in the historic proportions as well as the past 5-year average provides an analytical tool, or a ***"NAC Reasonability Test",*** to estimate in a simple fashion the total annual NAC estimates for the bridge year. High and low range estimates can be obtained by using the standard deviations present in the data for each proportion. Dividing the observed total January to March NAC by the trend proportion yields a simple statistical estimate of the total annual NAC for the bridge year.

16.1.2. How the Reasonability Test is used

The annual NAC estimates obtained from the NAC Gauge can be used to assess the NAC estimates obtained from the sum of the econometric analysis and the marketing plan NAC impact assessments. The econometric analysis is a robust statistical analysis that incorporates weather, energy efficiency and price related factors. The marketing plan NAC impacts build into the NAC forecast the expected consumption gains arising from marketing initiatives aimed at specific market segments or growth gas application opportunities. The marketing plan impacts are the first year impacts that cumulate over time. The NAC Gauge also provides a quick check on the current budget year NAC estimates.

The table below shows the January to March NAC proportions for each of the rate and service classes. This table was used to prepare the 2004 energy demand forecast. The bridge-year for this forecast is the year 2003. Note that the trend and past five-year average proportions are very close in most cases. Also note that the standard deviations of the proportions are generally similar in magnitude to the standard errors that are obtained from the econometric estimation and analysis.

The January to March trend and range proportions were applied to sum of the reported January and March 2003 NAC levels in order to derive the trend and range total NAC estimates shown in the table. All the NAC's were weather normalized using the 2004 declining trend weather normal. This illustrates the NAC Reasonability Test concept.

JANUARY TO MARCH NAC as % of TOTAL ANNUAL NAC TABLE

Year	Res M2	Res 01	Comm M2	Comm 01	Comm 10	Ind M2	Ind 10
1991	46.0%	44.7%	45.8%	46.7%	42.8%	41.0%	37.2%
1992	45.9%	44.6%	44.9%	47.1%	43.3%	42.2%	38.5%
1993	46.3%	45.4%	45.6%	47.8%	44.0%	40.5%	38.4%
1994	46.6%	45.5%	45.2%	48.1%	42.7%	41.9%	37.6%
1995	45.8%	45.3%	45.1%	47.2%	44.3%	40.6%	37.4%
1996	45.7%	44.8%	44.6%	46.9%	43.3%	41.5%	36.9%
1997	46.8%	46.8%	45.3%	46.9%	44.2%	42.4%	42.8%
1998	47.1%	48.4%	45.1%	51.2%	46.8%	40.1%	48.0%
1999	46.7%	45.0%	45.9%	46.9%	46.0%	40.5%	41.2%
2000	45.9%	43.9%	50.0%	44.9%	44.3%	41.9%	40.0%
2001	46.9%	45.7%	43.9%	49.0%	44.1%	41.9%	34.8%
2002	46.7%	46.1%	45.1%	49.1%	45.9%	39.4%	40.5%
past 5 Years	46.7%	45.8%	46.0%	48.2%	45.4%	40.8%	40.9%
Trend	**46.8%**	**46.0%**	**45.8%**	**48.4%**	**46.3%**	**40.8%**	**40.7%**
past 5: Trend	*99.7%*	*99.6%*	*100.4%*	*99.6%*	*98.2%*	*100.0%*	*100.5%*
Low Trend	46.3%	44.8%	44.3%	46.8%	45.0%	39.8%	37.2%
High Trend	47.3%	47.2%	47.3%	50.0%	47.5%	41.7%	44.1%
Std. Dev.	0.5%	1.2%	1.5%	1.6%	1.3%	0.9%	*3.5%*
As % of Trend	*1.1%*	*2.6%*	*3.3%*	*3.3%*	*2.7%*	*2.3%*	*8.5%*
Jan-March NAC	1,207	1,270	7,756	4,461	41,298	35,485	111,326

Estimated Annual NAC: m3 per Customer

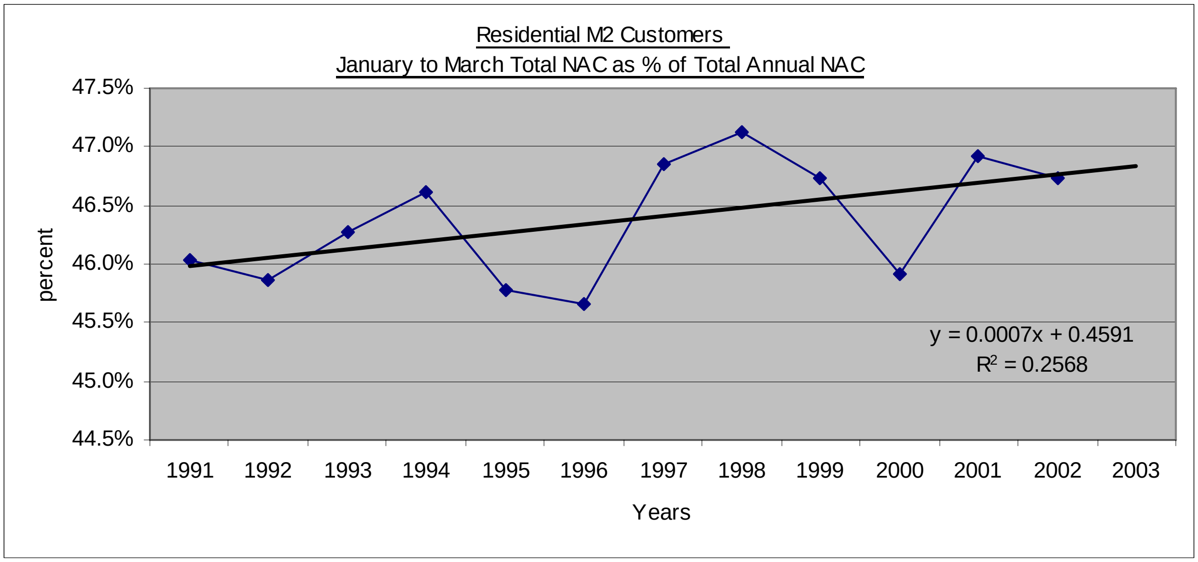
	Res M2	Res 01	Comm M2	Comm 01	Comm 10	Ind M2	Ind 10
Trend Estimate	2,578	2,760	16,934	9,217	89,293	87,079	273,589
Upper Range	2,607	2,834	17,514	9,534	91,825	89,142	299,001
Lower Range	2,551	2,690	16,392	8,920	86,898	85,109	252,158
Budget 2003	2,608	2,679	17,107	9,145	100,476	82,213	223,860

Preliminary NAC Estimates (First Draft Estimates)

	Res M2	Res 01	Comm M2	Comm 01	Comm 10	Ind M2	Ind 10
Econometric Estimate	2,611	2,710	17,394	9,071	95,348	87,129	291,335
DSM Plan	-4	-11	-52	-19	-198	(244)	(486)
Plus Mkt Plan	14	14	22	15	138	7	27
Total NAC Prelim.	2,621	2,713	17,364	9,067	95,288	86,893	290,876
Reasonability Test Adjustment	*(14)*	-	-	-	*(3,463)*	-	0
FINAL NAC Bridge Yr 2003	2,607	2,713	17,364	9,067	91,825	86,893	290,876

The NAC Reasonability Test suggests that the **Preliminary NAC** estimates for the year 2003 in the case of Residential Rate M2 & Commercial Rate 10 may be on the high side, when compared to the upper and lower limits as assigned by the reasonability tool. In this case, the relationship defined by the forecast equation is re-examined, the assumptions are checked and alternatives are examined. If all else fails then the suggested adjustment is made to the preliminary NAC estimates to line it up with the limit that it is closest to. This is done solely to ensure that the size of the reasonability adjustment is kept to a minimum. As in the case of the Residential Rate M2, a preliminary NAC estimate of 2,621 m*3 is deemed to be too high since it is outside of the band, i.e. the Upper & Lower limits of the Reasonability Test. Since the closest limit is the Upper limit, the preliminary estimates are lowered by 14 m*3 to 2,607 m*3. This adjustment is then made to all the years in the forecast horizon. Interestingly, the Actual 2003 Year NAC came in at 2,601 m*3.

The chart below further illustrates the January to March NAC proportions. The proportions for residential rate M2 customers are presented. The trend line shows how the proportions are changing over time. An increasing proportion indicates that base load is being lost over time. Loss of base load can result from various factors: replacement of pilot lights in new and replacement furnaces and water heaters with electronic ignition systems will lower the base load energy requirement, increased energy efficiency in furnaces and dwelling construction, and customer behaviour.



The NAC Reasonability Test is a very useful tool in the forecaster's toolkit. This tool relies on accurate and sound reported customer statistics for it to be valuable.

17. Appendices

ACTUAL HEATING DEGREE-DAYS: SOUTH RATE M2 & NORTH RATES 01& 10

HISTORICAL HEATING DEGREE DAYS - UNION SOUTH

Year	Jan	Feb	Mar	Apr	May	Non Heating Summer Months Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Htg. Deg.Days
1969	733.9	639.1	593.8	215.9	181.3	74.3	10.5	10.1	88.4	272.1	443.9	701.2	3,964.5
1970	812.9	660.9	621.7	312.7	136.2	41.2	5.6	8.0	73.8	200.1	409.6	659.5	3,942.2
1971	794.9	624.3	625.9	381.4	181.7	27.1	11.6	20.0	61.0	145.0	447.2	564.2	3,884.3
1972	724.7	722.5	643.1	416.5	128.2	80.4	23.5	24.7	79.3	335.4	486.8	616.9	4,282.0
1973	669.4	693.8	434.5	326.9	205.0	13.7	5.3	9.6	97.1	196.9	419.2	666.6	3,738.0
1974	701.5	697.8	567.4	313.0	224.4	41.8	6.8	4.9	127.5	308.7	430.2	611.9	4,035.9
1975	649.5	602.7	622.5	439.8	94.0	30.0	8.2	14.7	137.1	235.3	326.7	660.6	3,821.1
1976	827.4	573.3	499.3	307.6	205.3	19.5	8.8	30.4	114.5	344.9	545.2	779.5	4,255.7
1977	924.1	664.2	471.6	294.7	112.3	62.1	7.4	32.5	71.2	284.5	413.1	676.2	4,013.9
1978	814.7	802.0	677.1	384.4	165.8	55.6	16.6	5.6	83.8	290.9	440.2	633.3	4,370.0
1979	806.2	797.2	498.3	375.6	195.9	52.1	12.7	24.3	90.6	285.9	423.7	580.5	4,143.0
1980	714.2	735.0	612.1	346.4	136.6	86.4	4.4	1.3	90.4	339.2	474.7	724.2	4,264.9
1981	829.0	572.3	542.5	305.9	186.8	28.9	7.7	9.7	115.4	333.4	422.7	643.8	3,998.1
1982	846.4	711.7	600.2	397.9	85.5	67.6	5.1	41.6	102.7	238.1	407.5	506.6	4,010.9
1983	663.2	566.7	513.3	364.6	228.6	47.2	7.9	5.6	78.6	257.6	417.8	757.0	3,908.1
1984	836.3	553.0	683.1	322.6	228.8	22.8	12.5	10.5	117.4	207.8	442.2	560.2	3,997.2
1985	793.4	667.1	523.0	279.2	126.4	62.1	7.8	12.4	79.9	239.8	413.1	722.0	3,926.2
1986	723.7	665.4	527.6	299.7	126.1	52.6	9.3	37.2	87.1	259.9	490.5	602.7	3,881.8
1987	706.6	633.7	492.4	282.0	130.9	24.4	5.3	26.2	70.0	338.6	407.3	566.2	3,683.6
1988	720.0	702.5	559.7	339.5	126.8	53.1	2.9	14.8	86.2	343.7	397.1	640.1	3,986.4
1989	613.5	679.2	581.3	382.0	168.0	35.1	3.1	17.0	101.4	251.8	472.3	849.2	4,153.9
1990	583.4	586.1	502.5	303.0	195.3	39.0	6.2	8.0	98.9	269.4	393.6	586.1	3,571.5
1991	735.0	561.8	497.9	276.4	100.8	16.6	4.3	5.4	118.2	230.2	468.9	615.7	3,631.2
1992	676.5	622.6	574.6	376.2	168.1	72.3	26.8	40.7	109.2	314.5	447.0	602.2	4,030.7
1993	665.8	714.9	619.2	343.0	167.1	50.3	2.4	9.4	143.0	304.5	448.1	637.2	4,104.9
1994	905.8	729.9	578.2	318.0	205.5	38.1	4.1	27.1	81.1	238.4	369.4	559.2	4,054.8
1995	646.7	695.7	499.1	403.2	152.1	21.0	11.0	2.4	116.2	217.2	514.1	708.3	3,987.0
1996	757.8	683.1	650.5	393.4	201.0	20.5	11.3	2.8	79.6	258.0	517.8	576.7	4,152.5
1997	743.0	572.5	558.7	371.2	265.8	29.5	13.8	26.7	84.3	263.6	480.8	595.2	4,005.1
1998	608.1	504.9	492.5	289.3	68.0	59.4	1.5	6.2	44.5	225.9	393.8	530.6	3,224.7
1999	761.5	545.7	565.3	300.7	105.3	36.1	2.0	12.9	67.1	281.5	371.7	591.2	3,641.0
2000	734.5	603.2	422.2	343.0	134.0	33.7	12.6	19.4	111.3	217.2	440.4	804.9	3,876.5
2001	680.0	587.7	574.1	276.8	119.4	35.8	12.5	2.0	95.1	236.4	321.2	525.70	3,466.7
2002	577.5	537.8	540.1	319.2	218.3	35.8	0.5	3.4	28.5	294.7	445.2	634.6	3,635.6
2003	799.3	691.8	557.4	358.1	184.8	47.1	4.7	4.9	70.0	279.6	384.8	575.0	3,957.5

HISTORICAL HEATING DEGREE DAYS - UNION NORTH

Year	Jan	Feb	Mar	Apr	May	Non Heating Summer Months Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1969	895.5	747.8	746.7	275.3	282.1	150.2	39.3	25.7	169.5	392.0	553.5	842.9	5,120.5
1970	1,026.9	868.8	750.0	439.6	287.3	92.7	26.2	48.0	159.5	294.1	540.2	881.0	5,414.3
1971	1,023.9	802.8	764.9	469.8	270.4	75.2	54.1	77.5	125.2	241.3	575.8	793.2	5,274.1
1972	950.2	914.6	813.7	514.5	196.6	118.0	48.5	74.8	196.8	430.2	591.7	892.2	5,741.8
1973	855.9	846.6	541.6	422.3	270.7	77.6	26.2	20.5	188.1	276.2	564.7	850.6	4,941.0
1974	947.9	888.9	759.0	453.2	316.1	86.7	25.8	46.7	237.1	413.2	543.4	727.9	5,445.9
1975	871.3	763.5	764.9	524.7	151.2	71.7	26.4	46.1	206.4	324.5	509.0	874.3	5,134.0
1976	1,029.4	765.2	738.2	395.8	272.1	46.6	34.0	61.7	199.8	431.3	650.9	1,018.3	5,643.3
1977	1,054.6	786.4	588.2	407.3	165.3	119.6	38.4	98.8	170.9	367.0	533.7	857.9	5,188.1
1978	1,006.5	876.8	780.3	498.1	191.6	130.4	48.4	56.0	192.6	385.3	601.9	871.6	5,639.5
1979	1,008.5	967.7	667.8	465.0	261.6	107.0	34.4	83.1	177.1	395.4	546.1	744.2	5,457.9
1980	906.7	895.9	744.5	404.2	196.6	153.2	25.8	27.7	207.4	443.0	594.2	959.5	5,558.7
1981	994.7	693.9	641.0	420.9	255.0	102.9	27.0	30.3	203.4	420.2	522.7	780.3	5,092.3
1982	1,118.7	839.5	732.0	515.5	163.2	143.2	33.1	103.0	180.4	322.1	555.6	723.4	5,429.7
1983	876.3	726.1	663.8	465.1	318.6	93.9	22.1	21.1	136.4	356.8	552.6	962.5	5,195.3
1984	1,027.0	670.3	799.2	356.0	295.8	89.6	35.2	35.9	207.6	311.1	553.6	793.4	5,174.7
1985	994.5	815.9	672.4	428.3	225.4	137.4	51.7	64.7	156.0	342.5	614.6	934.4	5,437.8
1986	947.1	815.2	670.7	363.0	191.8	131.7	37.0	76.8	197.5	384.1	630.0	730.3	5,175.2
1987	846.3	741.0	619.2	322.4	218.1	69.5	28.1	61.5	135.3	417.3	550.2	713.5	4,722.4
1988	933.8	903.7	728.0	426.7	191.5	100.0	15.9	51.6	165.5	422.4	514.3	863.3	5,316.7
1989	855.2	874.2	798.9	481.5	208.6	104.6	21.9	64.7	159.0	348.0	658.7	1,078.9	5,654.2
1990	780.2	785.1	662.4	410.4	273.6	95.5	33.8	46.8	185.7	386.4	527.4	806.5	4,993.8
1991	972.1	733.0	667.0	371.0	176.4	52.7	30.7	38.1	200.9	368.6	586.3	821.7	5,018.5
1992	905.5	811.0	766.3	479.6	231.8	135.5	92.8	93.7	181.2	411.1	591.9	788.5	5,488.9
1993	903.8	887.6	704.0	450.8	254.8	110.0	22.6	33.8	235.8	431.7	621.5	803.9	5,460.3
1994	1,180.2	902.6	674.8	463.0	258.1	75.1	32.8	82.3	136.0	305.9	502.9	679.9	5,293.6
1995	831.7	861.6	642.8	516.2	237.5	59.5	32.1	29.1	210.4	329.4	701.9	905.6	5,357.8
1996	1,015.5	874.6	792.6	525.5	293.5	67.4	50.4	39.4	130.3	366.3	633.5	761.0	5,550.0
1997	987.3	798.9	764.3	466.6	336.6	51.1	47.3	77.3	154.1	363.3	594.5	742.8	5,384.1
1998	852.2	610.2	646.3	360.9	141.0	87.4	23.5	29.3	130.9	326.9	517.3	731.5	4,457.4
1999	956.3	686.7	676.6	382.5	165.3	64.1	16.1	58.4	134.1	389.2	482.3	742.4	4,754.0
2000	946.2	744.7	554.6	441.4	217.9	117.3	45.7	51.1	193.3	332.0	542.1	971.9	5,158.2
2001	827.9	790.4	679.3	383.9	172.7	69.9	43.0	27.7	155.4	337.2	449.8	654.5	4,591.8
2002	782.8	706.2	746.0	447.0	299.0	83.5	14.1	28.7	99.3	440.4	611.5	738.0	4,996.5
2003	978.9	869.3	717.9	487.5	199.9	74.5	24.7	27.1	120.4	368.5	519.3	723.2	5,111.2

2005 Budget Demand Forecast Weather Normal
OEB 70:30 BLENDED Weather Normal

Blend	Year	January	February	March	April	May	June	July	August	September	October	November	December	Total
Union South Heating Degree Days below 18 C														
70:30	2004	721.5	653.7	547.1	331.1	158.6	41.2	7.8	14.9	91.2	267.8	426.5	625.8	3,887.4
70:30	2005	720.9	630.5	546.6	330.8	158.5	41.2	7.8	14.9	91.1	267.6	426.1	625.2	3,861.2
60:40	2006	715.3	625.9	543.6	328.3	157.5	40.7	7.7	14.7	90.2	265.4	424.1	621.1	3,834.6
60:40	2007	714.4	625.1	542.9	327.9	157.3	40.7	7.7	14.7	90.1	265.1	423.5	620.3	3,829.8
Union North Heating Degree Days below 18 C														
70:30	2004	928.6	819.8	694.3	428.6	226.5	91.7	34.1	51.8	169.6	369.5	561.4	802.8	5,178.7
70:30	2005	927.6	790.7	693.6	428.2	226.3	91.6	34.0	51.8	169.4	369.1	560.8	801.9	5,145.0
60:40	2006	920.6	785.5	689.8	424.6	225.0	90.6	34.0	51.3	167.9	366.7	557.9	795.8	5,109.6
60:40	2007	919.3	784.4	688.8	424.0	224.6	90.5	34.0	51.2	167.7	366.2	557.1	794.7	5,102.4

ECONOMIC OUTLOOK - 2005 Demand Forecast
Canada & U.S.A.

Economic Indicator	Actual **2002**	Outlook **2003**	Outlook **2004**	Outlook **2005**	Outlook **2006**
U.S. Real GDP Ann. Growth Rate: % p.a.	2.4	3.1	4.9	4.3	
U.S. Light Vehicle Production: million units	16.7	16.5	16.8	16.7	
Canada Real GDP Ann. Growth Rate: % p.a.	3.3	1.6	2.8	3.1	2.8
Manufacturing GDP Ann. Growth Rate: % p.a.	2.6	-0.6	2.4	3.1	2.4
Machinery & Equipment Prices: % p.a.	-2.5	-9.8	-6.4	-5.4	-3.1
Machinery & Equipment Cap. Ex.: % p.a	-3.2	4.3	7.8	7.3	8.8
Total Housing Starts Canada: 000's	205.7	220.6	216.2	196.6	163.5
Canadian Unemployment Rate: %	7.6	7.6	7.6	7.5	7.7
Canadian Consumer Price Index: % p.a.	2.2	2.8	0.9	0.8	1.2
Canada USA Exchange Rate: U.S. $ in Cdn $	1.570	1.401	1.261	1.218	1.203
Canada 3-Month T Bills: %	2.59	2.9	2.33	2.53	3.39
GOC 10-Year Bonds: %	5.29	4.81	5.01	5.44	5.86
5-Year Mortgage Rates:%	7.02	6.29	5.45	5.51	6.34

source: Centre for Spatial Economics (C4SE) January 2004

Ontario Real GDP Growth by Industry
at 1997 chained dollars

Year	Total GDP	Goods Production	Auto Mfg	Service Sector
1998	4.9%	5.1%		4.7%
1999	7.6%	8.2%	20.8%	7.4%
2000	6.0%	7.4%	0.7%	5.3%
2001	1.3%	-2.8%	-9.4%	3.4%
2002	3.8%	3.5%	7.3%	4.0%
2003	1.4%	0.1%	0.8%	1.9%
2004	3.0%	2.9%	3.5%	3.1%
2005	3.3%	3.7%	4.1%	3.1%

NEW CUSTOMER ATTACHMENTS

	Residential Customers		Commercial Customers				Industrial Customers		Total
	Rate M2	Rate 01	Rate M2	Tobacco M2	Rate 01	Rate 10	Rate M2	Rate 10	Customers
2004	20,953	4,476	1,681		411	46	123	9	27,699
2005	20,385	4,524	1,630		311	132	119	9	27,110
2006	19,321	4,397	1,543		377	42	112	8	25,800
2007	18,628	4,301	1,476		361	41	108	8	24,923
DEMOLITIONS / LOST CUSTOMERS / RATE MIGRATION & RECLASSIFICATION									
2004	-683	-17	-50	-30	18	-38	-95	-7	-902
2005	-533	-164	-52	-30	101	-122	-93	-7	-900
2006	-632	-69	-50	-30	12	-32	-85	-6	-892
2007	-622	-78	-49	-30	10	-31	-82	-6	-888
NET CUSTOMER YEAR END GROWTH									
2004	20,270	4,459	1,631	-30	429	8	28	2	26,797
2005	19,852	4,360	1,578	-30	412	10	26	2	26,210
2006	18,689	4,328	1,493	-30	389	10	27	2	24,908
2007	18,006	4,223	1,427	-30	371	10	26	2	24,035

2005 DEMAND FORECAST
TOTAL NUMBER OF CUSTOMERS

CUSTOMERS AT DECEMBER 2003

Residential Customers		Commercial Customers				Industrial Customers		TOTAL
Rate M2	Rate 01	Rate M2	Tobacco M2	Rate 01	Rate 10	Rate M2	Rate 10	CUSTOMERS
827,198	254,998	77,957	977	25,375	2,567	5,224	189	1,194,485

TOTAL CUSTOMERS - ALL DSO

		Residential Customers		Commercial Customers				Industrial Customers		TOTAL
	Month	Rate M2	Rate 01	Rate M2	Tobacco M2	Rate 01	Rate 10	Rate M2	Rate 10	CUSTOMERS
Forecast	Jan-04	829,241	255,711	78,894	977	25,405	2,567	5,225	189	1,198,210
Forecast	Feb-04	830,795	256,045	79,126	977	25,398	2,568	5,227	189	1,200,324
Forecast	Mar-04	831,916	256,164	79,413	977	25,452	2,568	5,228	189	1,201,908
Forecast	Apr-04	832,542	256,107	79,488	977	25,728	2,569	5,230	189	1,202,830
Forecast	May-04	832,862	255,788	79,521	977	25,904	2,569	5,232	190	1,203,044
Forecast	Jun-04	832,858	255,512	79,080	977	25,846	2,570	5,235	190	1,202,268
Forecast	Jul-04	832,825	255,332	78,840	977	25,522	2,571	5,238	190	1,201,494
Forecast	Aug-04	830,107	255,124	78,603	977	25,763	2,572	5,241	190	1,198,576
Forecast	Sep-04	835,736	255,280	78,452	947	25,739	2,573	5,244	190	1,204,161
Forecast	Oct-04	840,133	256,626	78,728	947	25,756	2,573	5,246	191	1,210,201
Forecast	Nov-04	844,859	258,315	79,314	947	25,785	2,574	5,249	191	1,217,234
Forecast	Dec-04	847,468	259,457	79,588	947	25,804	2,575	5,252	191	1,221,282
Forecast	Jan-05	849,469	260,154	80,495	947	25,833	2,576	5,253	191	1,224,917
Forecast	Feb-05	850,991	260,480	80,719	947	25,826	2,576	5,255	191	1,226,985
Forecast	Mar-05	852,089	260,597	80,997	947	25,878	2,577	5,256	191	1,228,532
Forecast	Apr-05	852,702	260,541	81,069	947	26,143	2,577	5,257	191	1,229,428
Forecast	May-05	853,016	260,230	81,101	947	26,312	2,578	5,260	192	1,229,635
Forecast	Jun-05	853,011	259,960	80,674	947	26,257	2,579	5,262	192	1,228,882
Forecast	Jul-05	852,979	259,783	80,442	947	25,945	2,580	5,265	192	1,228,133
Forecast	Aug-05	850,317	259,580	80,213	947	26,176	2,581	5,268	192	1,225,273
Forecast	Sep-05	855,830	259,733	80,067	917	26,154	2,582	5,270	192	1,230,745
Forecast	Oct-05	860,136	261,049	80,334	917	26,170	2,583	5,273	193	1,236,655
Forecast	Nov-05	864,765	262,700	80,901	917	26,198	2,584	5,275	193	1,243,533
Forecast	Dec-05	867,320	263,817	81,166	917	26,216	2,585	5,278	193	1,247,492
Forecast	Jan-06	869,204	264,509	82,024	917	26,243	2,586	5,279	193	1,250,954
Forecast	Feb-06	870,636	264,833	82,236	917	26,237	2,586	5,281	193	1,252,919
Forecast	Mar-06	871,670	264,949	82,499	917	26,286	2,587	5,282	193	1,254,383
Forecast	Apr-06	872,247	264,894	82,568	917	26,536	2,587	5,283	193	1,255,225
Forecast	May-06	872,543	264,584	82,597	917	26,696	2,588	5,286	194	1,255,405
Forecast	Jun-06	872,538	264,316	82,194	917	26,643	2,589	5,289	194	1,254,680
Forecast	Jul-06	872,508	264,141	81,974	917	26,349	2,590	5,292	194	1,253,965
Forecast	Aug-06	870,002	263,939	81,757	917	26,567	2,591	5,294	194	1,251,262
Forecast	Sep-06	875,192	264,091	81,619	887	26,546	2,592	5,297	194	1,256,419
Forecast	Oct-06	879,246	265,397	81,871	887	26,562	2,593	5,300	195	1,262,051
Forecast	Nov-06	883,604	267,036	82,408	887	26,588	2,594	5,302	195	1,268,614
Forecast	Dec-06	886,009	268,145	82,659	887	26,605	2,595	5,305	195	1,272,400
Forecast	Jan-07	887,824	268,820	83,479	887	26,631	2,596	5,306	195	1,275,738
Forecast	Feb-07	889,204	269,136	83,681	887	26,625	2,596	5,308	195	1,277,633
Forecast	Mar-07	890,200	269,249	83,933	887	26,672	2,597	5,309	195	1,279,042
Forecast	Apr-07	890,756	269,195	83,999	887	26,910	2,597	5,310	195	1,279,850
Forecast	May-07	891,041	268,893	84,027	887	27,063	2,598	5,313	196	1,280,017
Forecast	Jun-07	891,036	268,632	83,641	887	27,013	2,599	5,315	196	1,279,320
Forecast	Jul-07	891,007	268,461	83,431	887	26,732	2,600	5,318	196	1,278,633
Forecast	Aug-07	888,593	268,264	83,224	887	26,940	2,601	5,321	196	1,276,026
Forecast	Sep-07	893,593	268,412	83,092	857	26,920	2,602	5,323	196	1,280,996
Forecast	Oct-07	897,499	269,687	83,333	857	26,935	2,603	5,326	197	1,286,437
Forecast	Nov-07	901,698	271,286	83,846	857	26,960	2,604	5,328	197	1,292,776
Forecast	Dec-07	904,015	272,368	84,086	857	26,976	2,605	5,331	197	1,296,435
control chek									59,712,921	59,712,921

TOTAL CUSTOMERS - ALL DSO

	Residential Customers		Commercial Customers				Industrial Customers		TOTAL
Year	Rate M2	Rate 01	Rate M2	Tobacco M2	Rate 01	Rate 10	Rate M2	Rate 10	CUSTOMERS
No. of Customers at Year End December									
2003	827,198	254,998	77,957	977	25,375	2,567	5,224	189	1,194,485
2004	847,468	259,457	79,588	947	25,804	2,575	5,252	191	1,221,282
2005	867,320	263,817	81,166	917	26,216	2,585	5,278	193	1,247,492
2006	886,009	268,145	82,659	887	26,605	2,595	5,305	195	1,272,400
2007	904,015	272,368	84,086	857	26,976	2,605	5,331	197	1,296,435
Annual Increase in Number of Customers at December									
2004	20,270	4,459	1,631	- 30	429	8	28	2	26,797
2005	19,852	4,360	1,578	- 30	412	10	26	2	26,210
2006	18,689	4,328	1,493	- 30	389	10	27	2	24,908
2007	18,006	4,223	1,427	- 30	371	10	26	2	24,035
Average Annual No. of Customers									
2003	817,445	253,810	77,587	994	25,104	2,564	5,205	191	1,182,899
2004	835,112	256,288	79,087	967	25,675	2,571	5,237	190	1,205,128
2005	855,219	260,719	80,681	937	26,092	2,580	5,264	192	1,231,684
2006	874,617	265,069	82,201	907	26,488	2,590	5,291	194	1,257,356
2007	893,039	269,367	83,648	877	26,865	2,600	5,317	196	1,281,909

2003 Pull

Segment	Dwtp Code	Dwtp Code Desc
Colleges/Universities	CEDCU	EDUCATION COLLEGE/UNIVERSITY
	PBIEDC	EDUCATION COLLEGE/UNIVERSITY
Elementary/Secondary Schools & Daycares	CEDPS	EDUCATION PRIMARY/SECONDARY
	PBIEDP	EDUCATION PRIMARY/SECONDARY
	CDAYCA	PERMANENT DAY CARE CENTRE
	CDIDAY	PERMANENT DAY CARE CENTRE
Heath Services	CDIHOS	HOSPITAL FACILITY
	CHOSP	HOSPITAL FACILITY
	PCOR	PERMANENT CORRECTIONAL FACILITY
	CDIPSY	PERMANENT PSYCHIATRIC INSTITUTION
	PPSYC	PERMANENT PSYCHIATRIC INSTITUTION
	CDIHEA	SENIOR/NURSING/HEALTH CARE
	CHEAL	SENIOR/NURSING/HEALTH CARE
Hotel/Motel	CHOTMO	HOTEL/MOTEL
	CIHOTM	HOTEL/MOTEL
Multi-Residential	CIAPTB	APARTMENT BUILDING
	MAPTBG	APARTMENT BUILDING
	CICNDO	CONDOMINIUM BUILDING
	MCNDOB	CONDOMINIUM BUILDING
	CIFUNC	MULTI-FAMILTY OTHER
	MFUNCD	MULTI-FAMILY OTHER
	MROW	ROW/TOWNHOUSE COMPLEX
Office	CIOFFI	OFFICE BUILDING
	COFFIC	OFFICE BUILDING
	CIOFFU	OFFICE BUILDING UNIT
	COFFUN	OFFICE BUILDING UNIT
Other	CCOMM	COMMERCIAL OTHER
	CICOMM	COMMERCIAL OTHER
	CISPEC	COMMERCIAL SPECIAL
	CSPEC	COMMERCIAL SPECIAL
	CIINST	INSTITUTIONAL OTHER
	CINSTO	INSTITUTIONAL OTHER
Recreation	CARENA	ARENA
	PBIARE	ARENA
	CAUDI	AUDITORIUM
	PBIAUD	AUDITORIUM
	CPOOL	COMMERCIAL POOL
	CENTER	ENTERTAINMENT FACILITY
	PBICEN	ENTERTAINMENT FACILITY
	OPARK	PARK LAND
	CTHEAT	THEATRE
Religious	CREL	RELIGIOUS FACILITY
	PBIREL	RELIGIOUS FACILITY
Restuarants	CIREST	RESTAURANT / FOOD SERVICE
	CREST	RESTAURANT / FOOD SERVICE
Retail	CILAUN	COMMERCIAL LAUNDROMATS
	CLAUN	COMMERCIAL LAUNDROMATS
	CGSCW	GAS STATION / CAR WASH
	CIRET	RETAIL BUILDING
	CRET	RETAIL BUILDING
	CIRETP	RETAIL PLAZA
	CRETPL	RETAIL PLAZA
	CRETPU	RETAIL PLAZA UNIT
Warehouse/Wholesale	CIWARE	WAREHOUSE FACILITY
	CWARE	WAREHOUSE FACILITY

Assumptions used for growth, decay & vacancy
(percentage per year)

	Floorspace Growth rates	Floorspace Decay Rates	Vacancy Rates
Office	0.25%	0.10%	5.00%
Elementary/Secondary School	0.25%	0.10%	5.00%
Health Service	0.25%	0.10%	5.00%
Retail	0.25%	0.10%	5.00%
Warehouse/Wholesale	0.25%	0.10%	5.00%
College/University	0.25%	0.10%	5.00%
Restaurant	0.25%	0.10%	5.00%
Recreation	0.25%	0.10%	5.00%
Hotel/Motel	0.25%	0.10%	5.00%
Religious	0.25%	0.10%	5.00%
Multi-residential	0.25%	0.10%	2.70%
Other	0.25%	0.10%	5.00%

2005 to 2007 DEMAND FORECAST
VOLUME EQUATION
REGRESSION EQUATION COEFFICIENTS

	Residential		Commercial		
Demand Variable	**Rate M2**	**Rate 01**	**Rate M2**	**Rate 01**	**Rate 10**
Adjusted R Square	98.9%	98.4%	98.6%	99.0%	98.6%
F	1,033.63	617.71	837.50	1,017.28	769.02
MAPE	1.3%	1.0%	1.5%	1.8%	2.0%
INTERCEPT	- 58,701.68	- 16,820.76	-38,960.44	- 2,121.44	- 7,163.48
VOLUME LAGGED	0.09	0.12	0.06	- 0.03	n/a
TOTAL CUSTOMERS	0.15	0.15	0.97	0.30	6.39
RETAIL GAS PRICE	- 338.27	- 13,437.33	- 71.72	- 1,281.48	- 5,982.22
HDD January	375.87	94.89	241.42	40.18	35.84
HDD February	363.13	89.03	244.19	41.18	36.55
HDD March	358.68	80.79	242.50	38.78	36.20
HDD April	315.95	69.17	225.27	32.62	32.27
HDD May	254.74	53.92	185.58	23.11	21.83
HDD September	161.15	66.49	95.68	15.02	13.55
HDD October	267.84	72.47	191.56	28.52	32.51
HDD November	321.18	87.86	242.01	34.04	36.20
HDD December	375.73	88.15	247.11	37.78	35.44

t-statistics for key demand variables in Volume Equations

	Residential		Commercial		
Demand Variable	**Rate M2**	**Rate 01**	**Rate M2**	**Rate 01**	**Rate 10**
INTERCEPT	- 7.28	- 6.50	- 5.15	- 1.67	- 2.67
VOLUME LAGGED	3.01	3.12	1.77	4.08	n/a
TOTAL CUSTOMERS	9.17	8.49	6.63	- 0.63	4.73
RETAIL GAS PRICE	- 1.82	- 2.11	- 0.57	- 0.70	- 2.71
HDD January	34.74	29.23	30.26	34.34	66.09
HDD February	24.60	18.79	23.31	24.98	58.16
HDD March	24.39	17.16	22.82	22.94	52.26
HDD April	15.02	11.53	14.09	14.63	29.65
HDD May	9.27	7.02	9.23	9.09	11.08
HDD September	4.26	7.83	3.56	5.61	4.66
HDD October	19.67	18.74	19.76	24.38	25.38
HDD November	36.30	31.47	36.81	36.49	41.71
HDD December	44.74	30.56	36.07	38.02	53.86

	Industrial	
Demand Variable	**Merged**	**Rate M2**
Adjusted R Square	98.3%	99.7%
F	297.58	5,404.70
MAPE	1.8%	1.8%
INTERCEPT	- 404,048.72	- 10,864.16
HDD Q1	74.77	
HDD Q2	50.05	
HDD Q4	71.34	
GDP(CAN&US)	57.42	
GAS/LFO PRICE RATIO	- 313,929.36	
CUSTOMERS	88.83	
Total Ind Vol M21016		0.84

t-statistics for key demand variables in Volume Equations

	Industrial	
Demand Variable	**Merged**	**Rate M2**
INTERCEPT	- 8.57	- 8.35
HDD Q1	31.82	
HDD Q2	6.15	
HDD Q4	21.63	
GDP(CAN&US)	2.00	
GAS/LFO PRICE RATIO	- 1.36	
Total Ind Vol M21016		103.85

Note: Industrial is a combination of Total Industrial

BASE YEAR

SECTOR	BASE YEAR EUI EXISTING			EUI - NEW STOCK		
	Space Heating	Water Heating	Other	Space Heating	Water Heating	Other
Office	2.23	0.15		2.007	0.135	0
Elementary/Secondary School	3	0.2		2.7	0.18	0
Health Service	3	1.1	0.5	2.7	0.99	0.45
Retail	2.1	0.15	0.1	1.89	0.135	0.09
Warehouse/Wholesale	1.4	0.1		1.26	0.09	0
College/University	2.8	0.4	0.5	2.52	0.36	0.45
Restaurant	2.5	1.4	1	2.25	1.26	0.9
Recreation	2.5	0.4		2.25	0.36	0
Hotel/Motel	1.9	0.5	0.2	1.71	0.45	0.18
Religious	2.1	0.4	0.0	1.89	0.36	0
Multi-residential	2.1	0.48	0.05	1.89	0.432	0.045
Other	2.6	0.4	0.5	2.34	0.36	0.45

SUMMARY OUTPUT: Consolidated Light Industrial Volume Equation Regression
Rates M2, 10 & 16

Regression Statistics	
Multiple R	99.3%
R Square	98.6%
Adjusted R Square	98.3%
Standard Error	8,733.4
Observations	32

ANOVA

	df	*SS*	*MS*	*F*	*Signif. F*	**DW**		
Regression	6	136,180,409,441.0	22,696,734,906.8	297.6	0.0	2.32	*No positive auto*	
Residual	25	1,906,799,919.6	76,271,996.8				*Inconclusive negative auto*	
Total	31	138,087,209,360.6				DW lwr	1.11	2.89
						DW uppr	1.82	2.18

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	- 404,048.7	47,165.2	- 8.6	0.0	- 501,187.1	- 306,910.3	- 501,187.1	- 306,910.3
HDD Q1	74.8	2.3	31.8	0.0	69.9	79.6	69.9	79.6
HDD Q2 (May & June)	50.1	8.1	6.2	0.0	33.3	66.8	33.3	66.8
HDD Q4	71.3	3.3	21.6	0.0	64.5	78.1	64.5	78.1
CAN-USA QTR - Qtr GDP	57.4	28.8	2.0	0.1	- 1.8	116.7	- 1.8	116.7
PM210LFO Ratio	- 313,929.4	230,909.4	- 1.4	0.2	- 789,495.9	161,637.1	- 789,495.9	161,637.1
Customers	88.8	8.4	10.6	0.0	71.6	106.1	71.6	106.1

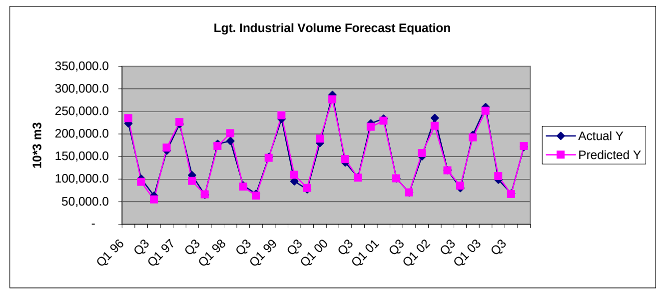
RESIDUAL OUTPUT

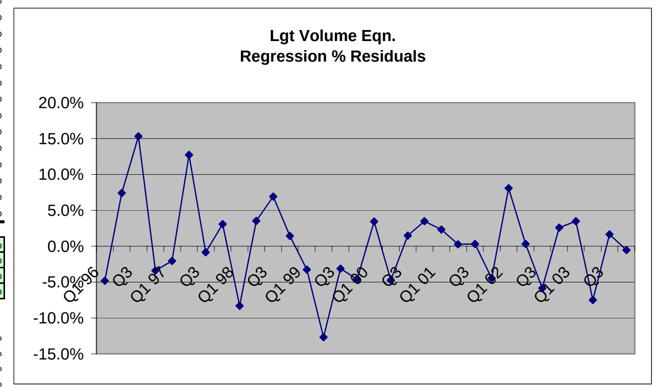
Observation	*Actual Y*	*Predicted Y*	*Residuals*	*%Resid.*	*Abs Resid.*	*% Abs Resid.*
Q1 96	223,754.5	235,105.1	- 11,350.7	-4.8%	11,350.7	4.8%
Q2	100,896.4	93,940.9	6,955.4	7.4%	6,955.4	7.4%
Q3	62,862.0	54,513.1	8,348.8	15.3%	8,348.8	15.3%
Q4	163,601.1	169,350.1	- 5,749.0	-3.4%	5,749.0	3.4%
Q1 97	221,998.8	226,617.1	- 4,618.3	-2.0%	4,618.3	2.0%
Q2	108,299.9	96,085.7	12,214.2	12.7%	12,214.2	12.7%
Q3	65,165.0	65,709.3	- 544.3	-0.8%	544.3	0.8%
Q4	178,467.7	173,130.6	5,337.1	3.1%	5,337.1	3.1%
Q1 98	184,749.7	201,487.3	- 16,737.6	-8.3%	16,737.6	8.3%
Q2	86,208.3	83,279.0	2,929.3	3.5%	2,929.3	3.5%
Q3	67,604.4	63,223.9	4,380.5	6.9%	4,380.5	6.9%
Q4	149,282.6	147,151.7	2,131.0	1.4%	2,131.0	1.4%
Q1 99	233,795.4	241,634.1	- 7,838.7	-3.2%	7,838.7	3.2%
Q2	95,187.5	108,996.4	- 13,808.9	-12.7%	13,808.9	12.7%
Q3	77,670.8	80,171.2	- 2,500.3	-3.1%	2,500.3	3.1%
Q4	180,677.7	189,376.6	- 8,698.8	-4.6%	8,698.8	4.6%
Q1 00	286,682.2	277,110.0	9,572.2	3.5%	9,572.2	3.5%
Q2	137,266.4	144,100.9	- 6,834.5	-4.7%	6,834.5	4.7%
Q3	104,407.2	102,906.7	1,500.5	1.5%	1,500.5	1.5%
Q4	223,343.4	215,796.0	7,547.5	3.5%	7,547.5	3.5%
Q1 01	234,424.2	229,066.0	5,358.1	2.3%	5,358.1	2.3%
Q2	101,656.3	101,399.1	257.2	0.3%	257.2	0.3%
Q3	70,387.3	70,177.0	210.3	0.3%	210.3	0.3%
Q4	150,537.0	157,600.1	- 7,063.1	-4.5%	7,063.1	4.5%
Q1 02	235,876.8	218,215.3	17,661.5	8.1%	17,661.5	8.1%
Q2	119,849.1	119,489.6	359.5	0.3%	359.5	0.3%
Q3	80,363.4	85,352.2	- 4,988.8	-5.8%	4,988.8	5.8%
Q4	197,741.1	192,713.0	5,028.1	2.6%	5,028.1	2.6%
Q1 03	259,728.1	250,970.9	8,757.2	3.5%	8,757.2	3.5%
Q2	98,734.5	106,717.6	- 7,983.1	-7.5%	7,983.1	7.5%
Q3	68,189.3	67,080.4	1,108.9	1.7%	1,108.9	1.7%
Q4	172,154.4	173,095.3	- 941.0	-0.5%	941.0	0.5%

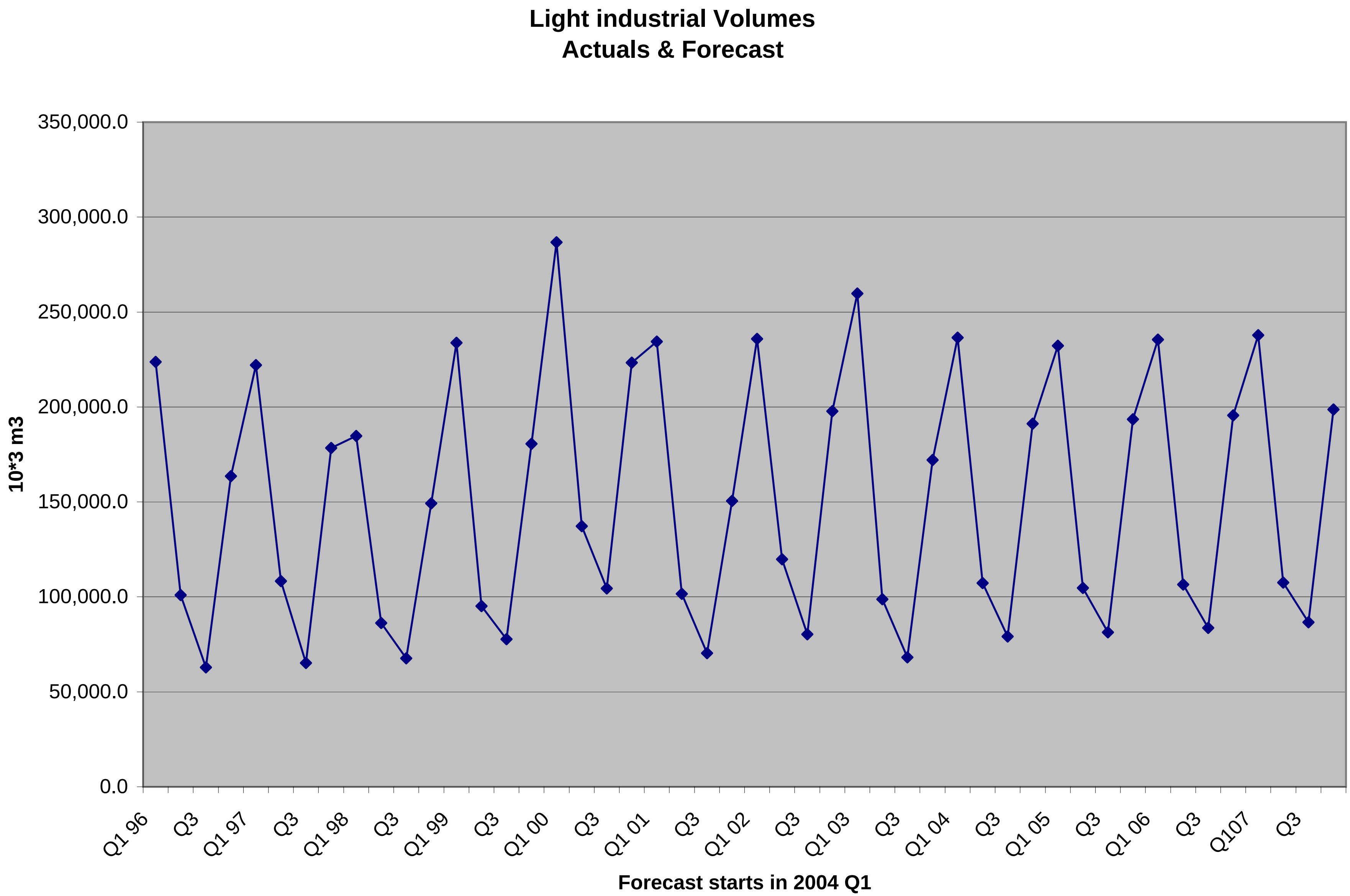
Q1	MAPE Q1	4.5%
Q2	MAPE Q2	6.1%
Q3	MAPE Q3	4.4%
Q4	MAPE Q4	3.0%

1996	551,113.9	552,909.3	- 1,795.4	-0.3%	-0.3%	0.3%
1997	573,931.3	561,542.7	12,388.6	2.2%	2.2%	2.2%
1998	487,845.0	495,141.9	- 7,296.9	-1.5%	-1.5%	1.5%
1999	587,331.4	620,178.2	- 32,846.8	-5.3%	-5.3%	5.3%
2000	751,699.3	739,913.7	11,785.6	1.6%	1.6%	1.6%
2001	557,004.7	558,242.2	- 1,237.5	-0.2%	-0.2%	0.2%
2002	633,830.4	615,770.1	18,060.3	2.9%	2.9%	2.9%
2003	598,806.3	597,864.3	942.0	0.2%	0.2%	0.2%
			MPE	-0.1%		
				MAPE	1.78%	

MPE - Mean Percent Error
MAPE - Mean Absolute Percent Error






Light industrial Volumes
Actuals & Forecast
350,000.0
300,000.0
250,000.0
200,000.0
150,000.0
100,000.0
50,000.0
0.0
10*3 m3
Q1 96
Q3
Q1 97
Q3
Q1 98
Q3
Q1 99
Q3
Q1 00
Q3
Q1 01
Q3
Q1 02
Q3
Q1 03
Q3
Q1 04
Q3
Q1 05
Q3
Q1 06
Q3
Q107
Q3
Forecast starts in 2004 Q1

LIGHT INDUSTRIAL VOLUME REGRESSION DATA (Rates M2, Banner and CIA 10 & 16)

		Rates M2 10 16 Total Volumes 10*3 m3	Weather Htg. Degree-Days 18C HDD Q1	HDD Q2	HDD Q4	Lagged 1 Qtr. North Am. GDP Qtr-Qtr Change 97 $ Billions	Natural Gas LFO Price Ratio	Total No. Customers
1996	Q1 96	223,754.5	2,239.2	0.0	0.0	60.3	0.0223	5,350
Act.	Q2	100,896.4	0.0	650.6	0.0	50.5	0.0233	5,289
Act.	Q3	62,862.0	0.0	0.0	0.0	130.8	0.0252	5,167
Act.	Q4	163,601.1	0.0	0.0	1,454.5	41.6	0.0199	5,330
1997	Q1 97	221,998.8	2,043.3	0.0	0.0	103.0	0.0252	5,402
Act.	Q2	108,299.9	0.0	678.6	0.0	87.4	0.0281	5,291
Act.	Q3	65,165.0	0.0	0.0	0.0	110.7	0.0301	5,323
Act.	Q4	178,467.7	0.0	0.0	1,429.8	94.6	0.0263	5,381
1998	Q1 98	184,749.7	1,731.3	0.0	0.0	51.5	0.0300	5,432
Act.	Q2	86,208.3	0.0	393.5	0.0	120.5	0.0369	5,317
Act.	Q3	67,604.4	0.0	0.0	0.0	42.6	0.0418	5,381
Act.	Q4	149,282.6	0.0	0.0	1,256.7	63.5	0.0367	5,285
1999	Q1 99	233,795.4	1,980.9	0.0	0.0	138.1	0.0384	5,648
Act.	Q2	95,187.5	0.0	441.5	0.0	84.8	0.0354	5,597
Act.	Q3	77,670.8	0.0	0.0	0.0	64.3	0.0318	5,522
Act.	Q4	180,677.7	0.0	0.0	1,334.0	116.0	0.0265	5,628
2000	Q1 00	286,682.2	1,881.3	0.0	0.0	168.1	0.0231	6,058
Act.	Q2	137,266.4	0.0	522.6	0.0	72.1	0.0260	5,922
Act.	Q3	104,407.2	0.0	0.0	0.0	102.0	0.0254	5,731
Act.	Q4	223,343.4	0.0	0.0	1,558.4	19.3	0.0232	5,796
2001	Q1 01	234,424.2	1,955.8	0.0	0.0	9.5	0.0307	5,583
Act.	Q2	101,656.3	0.0	436.3	0.0	- 14.2	0.0397	5,594
Act.	Q3	70,387.3	0.0	0.0	0.0	- 40.4	0.0452	5,524
Act.	Q4	150,537.0	0.0	0.0	1,172.9	- 10.4	0.0364	5,516
2002	Q1 02	235,876.8	1,800.3	0.0	0.0	51.2	0.0421	5,605
Act.	Q2	119,849.1	0.0	589.6	0.0	117.6	0.0302	5,592
Act.	Q3	80,363.4	0.0	0.0	0.0	114.1	0.0314	5,547
Act.	Q4	197,741.1	0.0	0.0	1,478.4	95.4	0.0284	5,569
2003	Q1 03	259,728.1	2,178.2	0.0	0.0	31.6	0.0258	5,611
Act.	Q2	98,734.5	0.0	579.0	0.0	64.8	0.0355	5,507
Act.	Q3	68,189.3	0.0	0.0	0.0	112.2	0.0470	5,397
Act.	Q4	172,154.4	0.0	0.0	1,332.6	226.3	0.0425	5,431

2005 to 2007 DEMAND FORECAST
USE EQUATION
REGRESSION EQUATION COEFFICIENTS

	Residential		Commercial			Industrial
Demand Variable	**Rate M2**	**Rate 01**	**Rate M2**	**Rate 01**	**Rate 10**	**Merged**
Adjusted R Square	99.7%	99.1%	99.0%	98.9%	98.6%	N/A
F	3,784.65	1,362.57	1,400.62	1,077.21	789.10	
MAPE	1.0%	1.6%	1.8%	2.7%	2.1%	
INTERCEPT	386.54	688.21	- 5,573.22	- 7,140.28	- 14,188.0	
EFFICIENCY	- 425.04	- 823.17	6,039.80	7,387.19	16,942.9	
GAS PRICE	- 0.48	- 41.50	n/a	- 261.89	- 1,979.9	
HDD January	0.64	0.52	3.82	1.87	16.63	
HDD February	0.63	0.51	3.93	1.91	16.98	
HDD March	0.62	0.47	3.89	1.80	16.89	
HDD April	0.59	0.43	3.78	1.54	15.51	
HDD May	0.52	0.37	3.11	1.19	11.52	
HDD September	0.31	0.35	1.08	0.90	7.89	
HDD October	0.44	0.38	2.87	1.48	15.69	
HDD November	0.52	0.46	3.70	1.64	16.89	
HDD December	0.60	0.47	3.81	1.77	16.41	

t-statistics for key demand variables in Use Equations

	Residential		Commercial			Industrial
Demand Variable	**Rate M2**	**Rate 01**	**Rate M2**	**Rate 01**	**Rate 10**	**Merged**
INTERCEPT	7.34	7.27	- 4.53	- 9.06	- 1.32	N/A
EFFICIENCY	- 6.06	- 6.52	4.87	9.30	1.57	
GAS PRICE	- 4.26	- 2.09	n/a	- 1.13	- 2.25	
HDD January	117.76	68.28	86.34	38.91	54.96	
HDD February	102.35	58.24	77.49	34.69	48.82	
HDD March	89.01	45.73	66.89	28.20	41.66	
HDD April	52.89	27.59	39.20	15.08	24.84	
HDD May	24.16	12.69	17.12	6.38	10.16	
HDD September	7.96	8.41	3.26	3.29	4.64	
HDD October	30.12	19.74	23.83	11.97	20.75	
HDD November	60.94	37.97	50.91	20.94	34.65	
HDD December	99.19	53.11	74.50	31.51	44.38	

2005 Marketing Plan
TOTAL THROUGHPUT VOLUME IMPACT: 10*3 M3

	2004	2005	2006	2007
Residential Rate M2	10,099.2	10,344.6	13,836.0	14,170.0
Residential Rate 01	3,123.3	3,171.2	4,206.4	4,271.4
Total Residential	13,222.5	13,515.7	18,042.4	18,441.4
Commercial Rate M2	8,675.3	8,848.8	9,025.8	9,206.3
Commercial Rate 01	2,823.8	2,880.3	2,937.9	2,996.6
Commercial Rate 10	285.7	291.4	297.2	303.1
Total Commercial	11,784.8	12,020.4	12,260.9	12,506.1
Tot. Res. & Comm.	**25,007.2**	**25,536.2**	**30,303.2**	**30,947.4**

ESTIMATED ANNUAL NAC IMPACT: m3 / customer

	2004	2005	2006	2007
Residential M2 & 01	12	12	16	16
Commercial M2	112	112	111	111
Commercial 01	112	114	114	114
Commercial 10	111	114	115	117

2005 Cost of Service
DSM Plan Total Volumes: 10*3 m3

	2004	**2005**	**2006**	**2007**
	Residential Rate M2			
2004	1,658.5	3,317.0	3,317.0	3,317.0
2005		1,691.7	3,383.3	3,383.3
2006			1,725.5	3,451.0
Total	**1,658.5**	**5,008.7**	**8,425.8**	**10,151.3**
	Residential Rate 01			
2004	480.5	961.0	961.0	961.0
2005		490.1	980.2	980.2
2006			499.9	999.8
Total	**480.5**	**1,451.1**	**2,441.1**	**2,941.0**
	Commercial & Industrial Rate M2			
2004	6,992.5	13,985.0	13,985.0	13,985.0
2005		7,132.4	14,264.7	14,264.7
2006			7,275.0	14,550.0
Total	**6,992.5**	**21,117.4**	**35,524.7**	**42,799.7**
Commercial M2	5,249.5	15,853.6	26,669.7	32,131.3
Industrial M2	1,743.0	5,263.8	8,855.0	10,668.4
	Commercial Rate 01& 10 & Industrial Rate 10			
2004	1,458.0	2,917.0	2,917.0	2,917.0
2005		1,487.2	2,974.3	2,974.3
2006			1,516.9	3,033.8
Total	**1,458.0**	**4,404.2**	**7,408.2**	**8,925.1**
Commercial 01	628.9	1,899.6	3,195.3	3,849.6
Commercial 10	680.7	2,056.1	3,458.6	4,166.8
Industrial 10	148.4	448.4	754.3	908.7
Total DSM	**10,589.5**	**31,981.3**	**53,799.9**	**64,817.2**

2005 DSM PLAN EST. NAC IMPACT: m3 per customer

	2004	**2005**	**2006**	**2007**
Residential M2	- 2	- 6	- 18	- 21
Residential 01	- 2	- 6	- 31	- 34
Commercial M2	- 66	- 196	- 492	- 615
Commercial 01	- 24	- 73	- 156	- 203
Commercial 10	- 265	- 797	- 1,720	- 2,263
Industrial M2	- 332	- 991	- 2,464	- 3,110
Industrial 10	- 774	- 2,266	- 4,745	- 6,117

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 1, Figure 1

a) Please provide the Statistics for the 20 year declining trend line and the existing weather normal method.

b) Graph actual and the proposed 20 year declining trend and the current approved weather normal line on a Version of Figure 1. (larger scale) Discuss the differences.

c) Please provide summary details of weather data supporting the North and South franchise HDD estimates. Source (e.g. Environment Canada), number and location of weather stations and period of data.

d) Show how the HDD and weather normal variables current and proposed, are derived from the data. Discuss data driven errors.

Response:

a) Please refer the 2013 REGN DATA File_Apr 2012 Excel file on the tab labeled Weather Union HDD. This weather data is trended by the 20-year trend weather normal methodology and projected to 2013, see 20 Yr Trend Normal tab.

b) Please refer the 2013 REGN DATA File_Apr 2012 Excel file. In the tab labeled Weather Union HDD are three charts that compare the weather normal methodologies for the Southern, Northern and total Company franchise areas. The three charts show that the 20-year trend weather normal is superior to the other methods in that it is a more accurate and provides a symmetric estimate.

c) Please see the response at Exhibit J.C-2-4-1 a).

d) Please see the response to c) above. Weather data revisions either by Environment Canada or the e-weather service provider is recorded as discovered, replacing previously reported data.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 1, Page 16: Appendix A Table 6

a) Explain in some detail the genesis of the Harvest Season Variable. For example, is it related (physically and statistically) directly to one or more measurable weather characteristics, cloud cover etc.?

b) Why is such a variable also not applicable to general service residential demand?

Response:

a) Statistical analysis of the energy usage data gave rise to the harvest variable. The annual energy usage pattern in the commercial market changed after 2006.

   The change was examined and explained by lagging the weather data for August to October by two months. This pointed to a production process that occurs during the autumn. An agricultural process is considered to be the source of the pattern. The regression analysis performed on the data including 2011 data continues to show this variable as significant. The variable is not related to other weather characteristics.

b) The residential and industrial markets do not exhibit the same energy usage pattern observed in the commercial market. The harvest variable as discussed above was developed to explain the new pattern present in the commercial market.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 1, Page 21, 3.4/ DSM Plan Impact

Significant changes to forecast DSM related savings resulted from the 2012-2013 DSM Plan Settlement Agreement.

Please provide an update of the demand forecast of 64,000 10 3 m 3 and sector estimates (residential 21,101 10 3 m 3) consistent with the Settlement Agreement for Resource Acquisition Programs.

Response:

The DSM related volume savings resulting from the 2012-2013 DSM Plan Settlement Agreement for 2011, 2012 and 2013 for the general service rate service sectors are provided below.

	Volume Savings (10^3 m^3)
Residential	15,857
Commercial	36,594
Industrial	12,657
Total	65,108

UNION GAS LIMITED

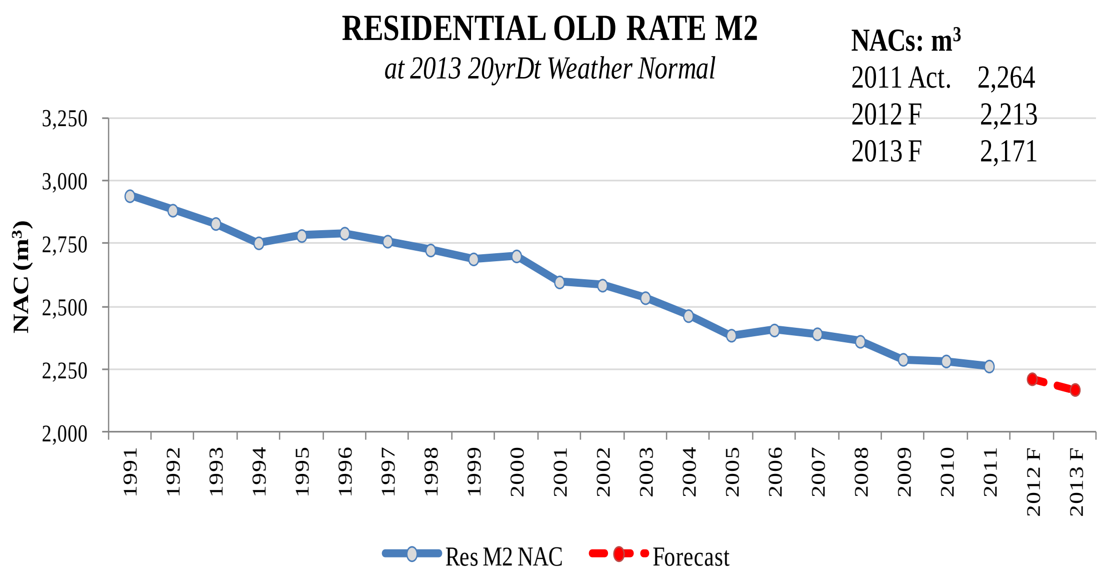
Answer to Interrogatory from
Energy Probe

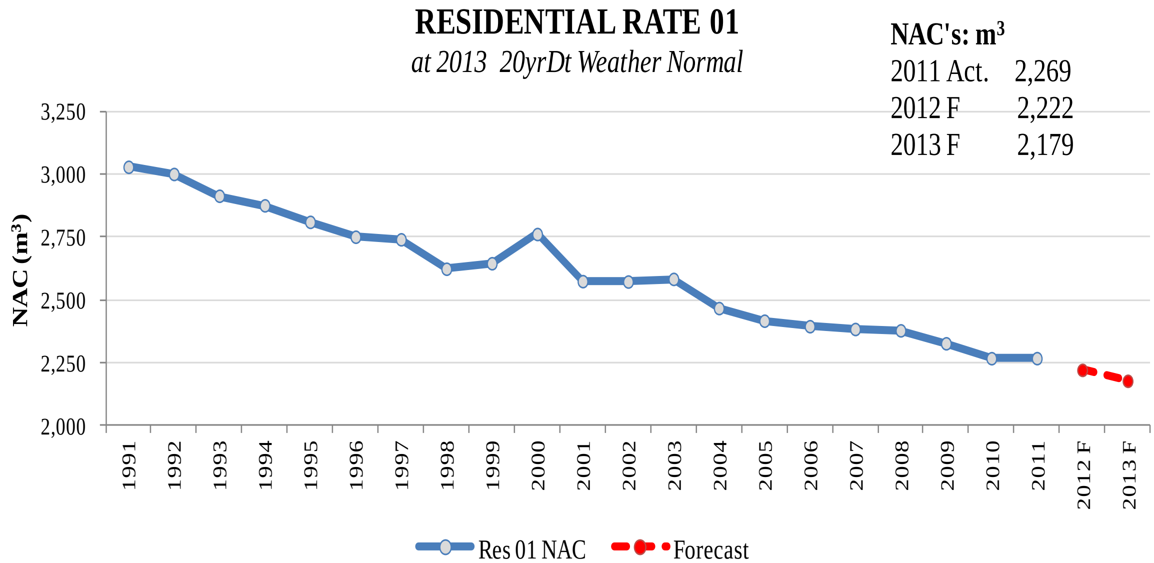
Ref: Exhibit C1, Tab 1, Pages 23-25

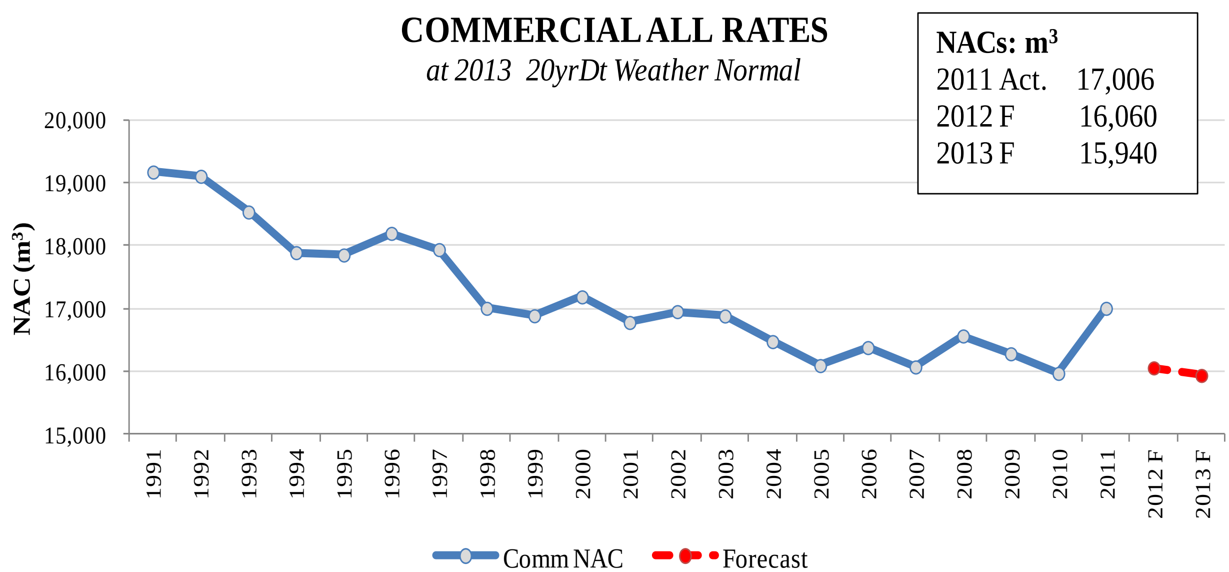
Please update Figures 5-8 to reflect 2011 actuals and revised 2012 and 2013 NAC, including DSM impacts.

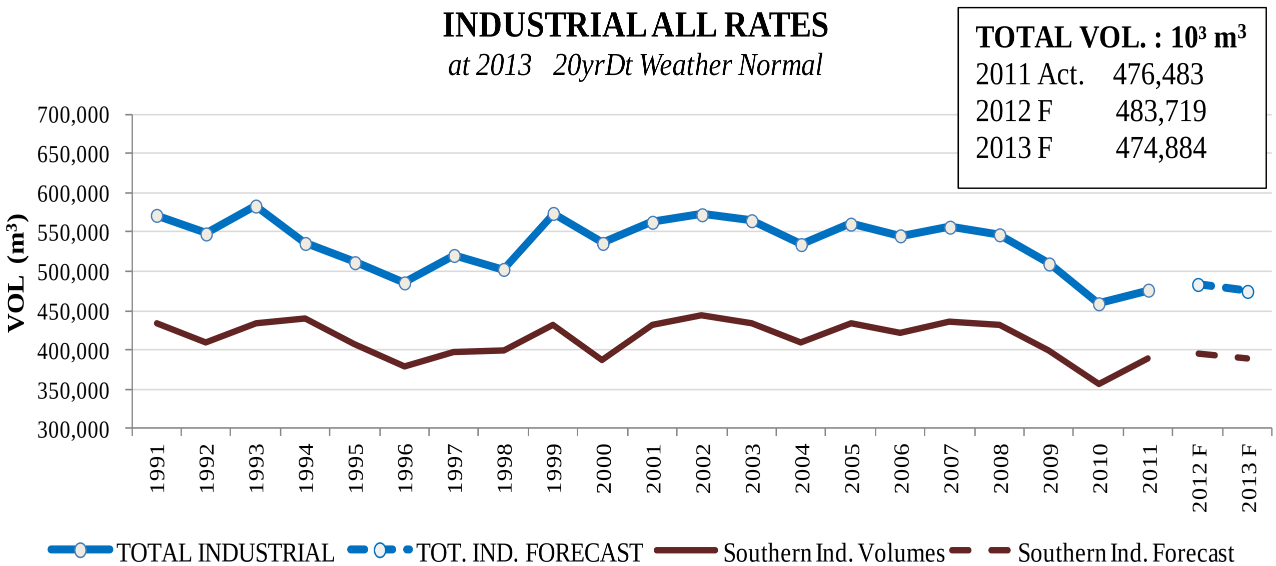
Response:

Please see the charts below.




RESIDENTIAL RATE 01
at 2013 20yrDt Weather Normal
NAC's: m3
2011 Act. 2,269
2012 F 2,222
2013 F 2,179
NAC (m3)
3,250
3,000
2,750
2,500
2,250
2,000
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012 F
2013 F
Res 01 NAC
Forecast


COMMERCIAL ALL RATES
at 2013 20yrDt Weather Normal
NACs: m3
2011 Act. 17,006
2012 F 16,060
2013 F 15,940
NAC (m3)
20,000
19,000
18,000
17,000
16,000
15,000
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012 F
2013 F
Comm NAC
Forecast


INDUSTRIAL ALL RATES
at 2013 20yrDt Weather Normal
TOTAL VOL. : 10^3 m^3
2011 Act. 476,483
2012 F 483,719
2013 F 474,884
VOL (m^3)
700,000
650,000
600,000
550,000
500,000
450,000
400,000
350,000
300,000
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012 F
2013 F
TOTAL INDUSTRIAL
TOT. IND. FORECAST
Southern Ind. Volumes
Southern Ind. Forecast

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 1, Page 11, Table 6

Please provide the supporting analysis for the Fall Weather Coefficient including causality and forecast results and forecast accuracy with/without the variable

---

Response:

Table 1 and 2 and Figure 1 below provide the regression results for the commercial market energy demand equation including the harvest season variable.

Table 1 shows the regression results for the data period January 1991 to December 2011. Very good regression results were obtained, especially the adjusted R Square values and the t statistics for all the demand variables. The shaded columns to the right in the top table shows the regression results for the 1991 to 2010 monthly data that was originally filed in evidence.

Table 2 shows how well the regression equation estimated the energy usage per customer over the historic period; the mean absolute percent error (MAPE) is 1.2 percent. The chart provides a rolling measurement of annual energy usage. The chart compares the actual usage against the predicted usage as measured by a rolling 12 month total consumption measure; the MAPE is 1.1%.

TABLE 1 - REGRESSION SUMMARY OUTPUT: COMMERCIAL MARKET USAGE

Regression Statistics		
Multiple R	99.6%	
R Square	99.3%	
Adjusted R Square	99.2%	
Standard Error	88.1	
Observations	252	Jan 1991 to Dec 2011

ANOVA

	df	*SS*	*MS*	*F*	*Signif. F*	*D.W.*
Regression	14	254,790,173	18,199,298	2,344	0.0	1.69
Residual	237	1,839,893	7,763			
Total	251	256,630,066				

	Coefficients	*Std Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	781.53	53.9	14.5	0.0%	675.4	887.6
Jan	3.74	0.0	122.3	0.0%	3.7	3.8
Feb	3.75	0.0	106.9	0.0%	3.7	3.8
Mar	3.73	0.0	91.6	0.0%	3.6	3.8
Apr	3.44	0.1	49.9	0.0%	3.3	3.6
May	2.83	0.1	21.2	0.0%	2.6	3.1
Sep	1.02	0.3	4.0	0.0%	0.5	1.5
Oct	2.84	0.1	32.7	0.0%	2.7	3.0
Nov	3.45	0.1	42.8	0.0%	3.3	3.6
Dec	3.36	0.1	24.2	0.0%	3.1	3.6
lag Weather	0.78	0.3	2.3	2.0%	0.1	1.4
Trend Htg Season	-1.66	0.2	-8.7	0.0%	-2.0	-1.3
Trend Base Load	-53.89	23.2	-2.3	2.1%	-99.6	-8.2
Dumy1	599.09	90.0	6.7	0.0%	421.7	776.5
Dumy2	-543.85	91.2	-6.0	0.0%	-723.4	-364.3

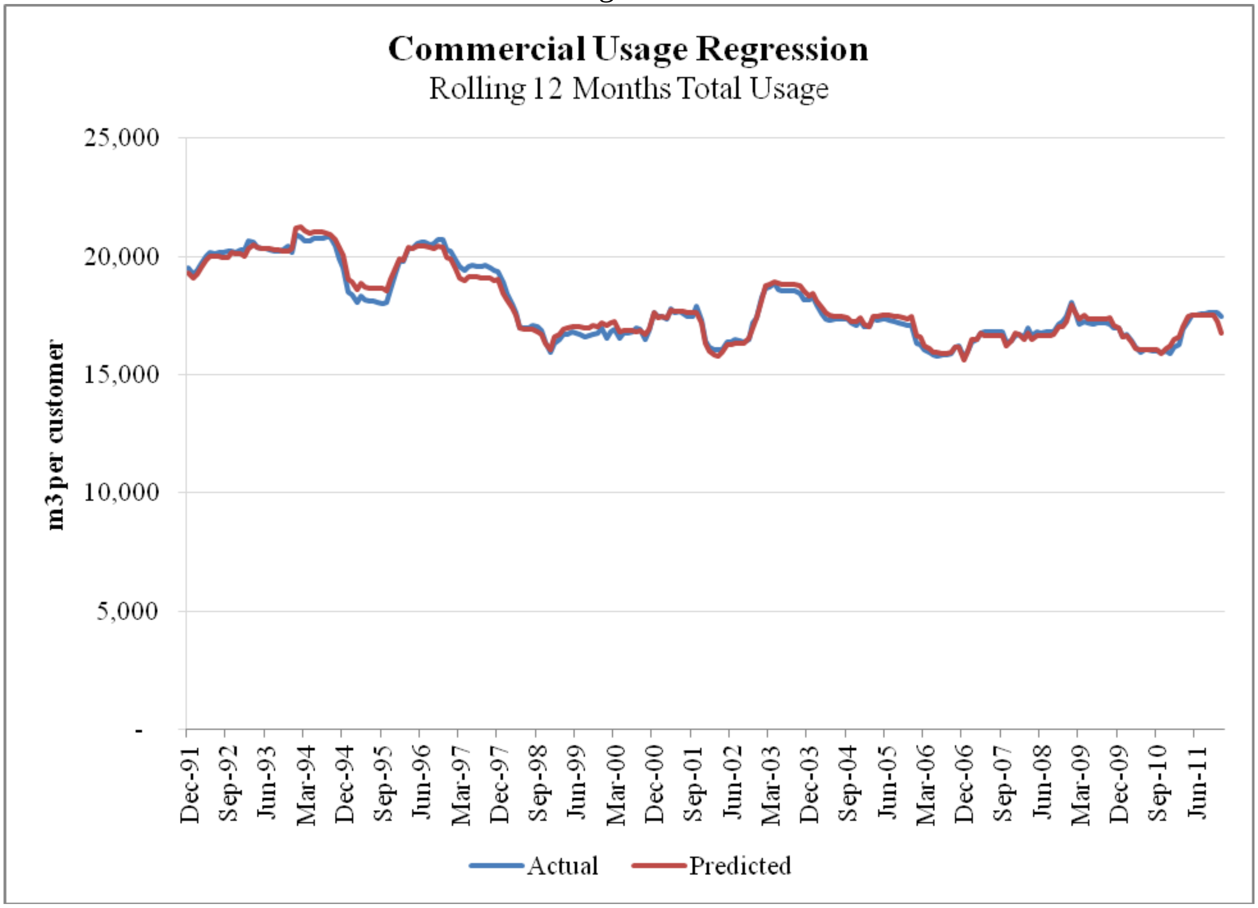
REGRESSION RESULTS
Filed in Evidence: 1991 to 2010

Coefficients	***t Stat***	***P-value***
782.57	14.78	0.0%
3.75	121.48	0.0%
3.77	106.84	0.0%
3.73	90.91	0.0%
3.45	49.77	0.0%
2.83	21.20	0.0%
1.02	3.98	0.0%
2.87	32.95	0.0%
3.45	43.38	0.0%
3.40	24.87	0.0%
0.67	2.04	4.3%
-1.69	-9.02	0.0%
-50.82	-2.23	2.7%
602.58	6.82	0.0%
-546.33	-6.10	0.0%

TABLE 2 - COMMERCIAL MKT USE PER CUSTOMER: m^3 / customer

Year	*Actual Y*	*Predicted Y*	*Residuals*	*Abs Resid*	*Abs %*
1991	19,546	19,314	233	233	1.2%
1992	20,308	20,099	210	210	1.0%
1993	20,201	20,337	-136	136	0.7%
1994	19,541	20,052	-511	511	2.5%
1995	19,332	19,529	-198	198	1.0%
1996	20,268	19,981	287	287	1.4%
1997	19,365	19,019	346	346	1.8%
1998	15,946	16,049	-103	103	0.6%
1999	16,957	17,190	-233	233	1.4%
2000	17,618	17,616	3	3	0.0%
2001	16,431	16,327	104	104	0.6%
2002	17,423	17,396	27	27	0.2%
2003	18,190	18,321	-131	131	0.7%
2004	17,287	17,409	-123	123	0.7%
2005	17,101	17,491	-390	390	2.2%
2006	15,748	15,626	121	121	0.8%
2007	16,682	16,741	-59	59	0.4%
2008	17,495	17,267	229	229	1.3%
2009	16,993	17,006	-13	13	0.1%
2010	15,883	16,243	-361	361	2.2%
2011	17,444	16,744	700	700	4.2%
				MAPE	**1.2%**

Figure 1



Tables 3 and 4 show the results excluding the harvest variable. The regression results are inferior. Table 3 reports a weaker standard error and Durbin Watson (DW) result for the regression estimation. Also, the MAPE of 1.3 percent is larger compared to 1.2 percent when the harvest variable is included. Table 4 shows that the residuals presented over the past 5 years, 2007 to 2011 are larger if the harvest variable is excluded.

TABLE 3

REGRESSION SUMMARY OUTPUT: COMMERCIAL MARKET USAGE - "NO HARVEST VARIABLE"

Regression Statistics		
Multiple R	99.6%	
R Square	99.3%	
Adjusted R Square	99.2%	
Standard Error	88.93	
Observations	252	Jan 1991 to Dec 2011

ANOVA

	df	*SS*	*MS*	*F*	*Signif*	*D.W.*
Regression	13	254,747,672.71	19,595,974.82	2,477.61	0.00	1.58
Residual	238	1,882,393.64	7,909.22			
Total	251	256,630,066.36				

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	790.70	54.21	14.59	0.00%	683.90	897.50
Jan	3.74	0.03	121.16	0.00%	3.68	3.80
Feb	3.75	0.04	105.85	0.00%	3.68	3.81
Mar	3.73	0.04	90.76	0.00%	3.64	3.81
Apr	3.43	0.07	49.40	0.00%	3.30	3.57
May	2.82	0.13	20.96	0.00%	2.56	3.09
Sep	1.01	0.26	3.87	0.01%	0.49	1.52
Oct	2.87	0.09	33.27	0.00%	2.70	3.04
Nov	3.59	0.05	68.54	0.00%	3.49	3.69
Dec	3.68	0.04	102.39	0.00%	3.61	3.75
Trend Htg Season	- 1.69	0.19	- 8.82	0.00%	- 2.07	- 1.31
Trend Base Load	- 55.55	23.42	- 2.37	1.85%	- 101.69	- 9.40
Dumy1	599.52	90.89	6.60	0.00%	420.46	778.58
Dumy2	- 543.03	92.01	- 5.90	0.00%	- 724.28	- 361.77

TABLE 4 - COMMERCIAL MKT USE PER CUSTOMER: m^3 / customer

Year	*Actual Y*	*Predicted Y*	*Residuals*	*Abs Resid*	*Abs %*
1991	19,546	19,349	197	197	1.0%
1992	20,308	20,038	270	270	1.3%
1993	20,201	20,287	-87	87	0.4%
1994	19,541	20,046	-505	505	2.5%
1995	19,332	19,594	-262	262	1.3%
1996	20,268	19,997	271	271	1.4%
1997	19,365	19,005	360	360	1.9%
1998	15,946	16,079	-133	133	0.8%
1999	16,957	17,173	-216	216	1.3%
2000	17,618	17,665	-46	46	0.3%
2001	16,431	16,281	150	150	0.9%
2002	17,423	17,418	4	4	0.0%
2003	18,190	18,293	-103	103	0.6%
2004	17,287	17,430	-143	143	0.8%
2005	17,101	17,556	-455	455	2.6%
2006	15,748	15,532	216	216	1.4%
2007	16,682	16,832	-150	150	0.9%
2008	17,495	17,261	234	234	1.4%
2009	16,993	16,959	35	35	0.2%
2010	15,883	16,257	-374	374	2.3%
2011	17,444	16,708	737	737	4.4%
				MAPE	**1.3%**

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 1, Page 20, Table 6 and Page 22, line 7

The forecast saved volumes from DSM in the industrial market are 7,387 10^3m^3 and account for approximately 12% of the total volume savings from DSM.

If Industrial customers achieve an "opt out" in 2013, what will be the impact on the forecast 2013 DSM savings for the sector and in total?

Response:

Industrial market DSM savings of 7,387 10^3m^3 are applicable to industrial general service customers.

If a provision of an "opt out" option is directed by the Board, there will be no impact on industrial general service DSM savings.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 1, Figures 5-8

a) Please provide 2011 actual NACs and discuss how this affects the 2012 and 2013 forecasts.

b) Is Union open to continue the NAC true ups implemented during IRM? Please discuss.

Response:

a) Please see Exhibit C1, Tab 1, Appendix A, Table 2 Updated.

   Please see the response at Exhibit J.C-1-2-4.

b) Union anticipates filing its application and evidence for its next IR mechanism after 2013 rates have been finalized. Union will address the use of NAC true-ups, if applicable, at that time.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 1, Appendix A, Table 8

a) Please discuss why the ex-post error of 3.9% for Rate 01 is acceptable forecast accuracy.

b) Please provide the ex-post error for 2011 and discuss the implications of this for the 2013 forecast.

Response:

a) The ex-post error of 3.9% for the use equation for Rate 01 is acceptable because the use equation estimate is not considered in isolation. The estimate from the use equation is combined with the estimate of the volume equation estimate which has a 2.1% ex-post error; this produces the final econometric estimate. The final econometric has an ex-post error of 0.9% which is very good.

b) The ex-post error for 2011 is presented in the table below.

In two of three markets the ex-post error improved. The ex-post error in the residential estimation is smaller and closer to 0% compared to the previously filed ex-post error for the year 2010. The residential market represents about 60% of the total throughput: 45% in the south and 15% in the north.

The industrial ex-post error at -5.2% is much smaller than the original estimate for 2010 of 21.1%. The industrial market is about 10% of total throughput volumes.

The commercial ex-post error at -4.5% is larger than the original estimate for 2010 of 1.0%. Weighting the ex-post forecast errors for each of the four markets by their volumetric weights yields an aggregate error of 2%.

Forecast Accuracy - 2013 Demand Forecast Equations

Annual Estimate Percentage error - Ex Post Error for 2011

	Use Eqn.	Volume Eqn.	Forecast
Residential Rate M2	0.3%	-0.6%	-0.1%
Residential Rate 01	-1.5%	0.9%	-0.3%
Commercial All Rates	-4.5%		-4.5%
Industrial All Rates		-5.2%	-5.2%

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit C1, Tab 1
Exhibit C1, Summary Schedules 1, 2, 3 and 4

With respect to this information, please provide revised Exhibit C1, Summary Schedules 1 (Throughput), 3 (Sales Revenue), and 4 (Delivery Revenue) for each of the following scenarios:

a) The Weather Normalization Method used to forecast general service demands remains unchanged;

b) The existing Weather Normalization Method is changed to a 50/50 ratio between the 30 year average and the 20 day declining trend methods; and

c) The existing Weather Normalization Method is changed to a 40/60 ratio of the 30 day average and the 20 year declining trend methods.

Response:

a) - c) Attachment 1 shows the estimated differences for total throughput volumes, total delivery revenue and total sales revenue for the year 2013 when the 2013 weather normal is restated using the 55:45, 50:50 and 40:60 blend of the 30-year average and the 20-year declining trend weather normal method.

If 55:45 Blended Normal

		Volumes: $10^3\ m^3$	Del. Rev. $000's [1]	Sales. Rev. $000's [1]
Residential Volume	Rate M1	59,685	2,529	13,716
	Rate M2	101	4	23
	Rate 01	27,123	1,919	7,968
Commercial volume	Rate M1	18,327	728	4,164
	Rate M2	16,234	674	3,717
	Rate 01	6,173	399	1,780
	Rate 10	6,078	272	1,570
Industrial Volume	Rate M1	1,559	61	353
	Rate M2	7,567	306	1,725
	Rate 10	788	27	200
	CIA 10	1,047	36	265
Total	Volumes	144,681	6,956	35,480

If 50:50 Blended Normal

		Volumes: $10^3\ m^3$	Del. Rev. $000's [1]	Sales. Rev. $000's [1]
Residential Volume	Rate M1	54,260	2,299	14,768
	Rate M2	91	4	25
	Rate 01	24,657	1,745	8,989
Commercial volume	Rate M1	16,661	662	4,447
	Rate M2	14,758	613	3,992
	Rate 01	5,612	362	1,980
	Rate 10	5,526	247	1,675
Industrial Volume	Rate M1	1,417	56	377
	Rate M2	6,879	278	1,846
	Rate 10	716	25	206
	CIA 10	951	33	273
Total	Volumes	131,528	6,324	38,578

If 40:60 Blended Normal

		Volumes $10^3\ m^3$	Del. Rev. $000's [1]	Sales. Rev. $000's [1]
Residential Volume	Rate M1	43,408	1,839	11,814
	Rate M2	73	3	20
	Rate 01	19,726	1,396	7,191
Commercial volume	Rate M1	13,329	530	3,558
	Rate M2	11,806	490	3,193
	Rate 01	4,490	290	1,584
	Rate 10	4,421	198	1,340
Industrial Volume	Rate M1	1,134	44	301
	Rate M2	5,503	223	1,477
	Rate 10	573	20	165
	CIA 10	761	26	219
Total	Volumes	105,223	5,059	30,862

Note: 1 at Jan 2012 QRAM rates

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2, T1, Schedule 1, Page 19

Please provide any studies Union has done itself, or had done by third party experts, to support the change to a twenty year declining trend weather normalization method, and to support its claim that the current method has resulted in the overestimation of heating demand of customers by 2.9% in a typical year. How much would the revenue forecast and throughout forecasts be reduced by this proposed change? What would be the impact of such a change on (a) upstream transportation and (b) balancing costs? Please show calculations.

Response:

Exhibit C1 Tab 5 describes the current cold weather bias present in the current blended weather normal methodology. The 20-year trend is symmetric. The 2.9% overestimation of heating demand is the difference between the two total throughput volume estimates for 2013 assuming the normal estimates of each methodology.

In 2013 the total throughput volume difference is 145 million cubic metres if the current blended 55:45 weather normal is used instead of the 20-year trend methodology. The total delivery revenue changes by approximately $7 million.

Using the 20-year declining trend weather normal methodology will decrease the forecast demand requirements from the demand forecast included in rates today. A reduction in demand requirements will result in less upstream transportation capacity assignments and less gas supply being purchased. Any variations in the supply requirements would be absorbed in the Dawn supply quantities and as a result upstream transportation would not be impacted.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2, T1, Schedule 1, Page 21

What requirements are included in the throughout forecasts each year from 2013 to 2018, inclusive, for the Thunder Bay Generating Station? Please provide a copy of the Minister's directive to the OPG for the conversion of the station from coal to gas.

Response:

The Thunder Bay throughput forecast for 2013 is 5000 10^3m^3 and for 2014 32,500 10^3m^3. Union does not have a throughput forecast for 2015 to 2018. Please see the Thunder Bay leave to construct filing EB-2012-0226 for the revenue forecast that underpins the project economics.

Please see Attachment 1.

Ministry of Energy

Office of the Minister

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Ministère de l'Énergie

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Ontario

AUG 17 2011

MC-2011-2974

Mr. Colin Andersen
Chief Executive Officer
Ontario Power Authority
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Andersen:

RE: Thunder Bay Generating Station Conversion to Natural Gas

I write to you pursuant to my authority as the Minister of Energy to exercise the statutory power of ministerial direction that I have in respect of the Ontario Power Authority (**"OPA"**) under section 25.32 of the *Electricity Act, 1998*.

Ontario's Long-Term Energy Plan, released in November 2010, proposed converting two coal-fired units at the Ontario Power Generation (**"OPG"**) Thunder Bay Generating Station to natural gas. These converted units are needed not only for local supply to the city of Thunder Bay, but also for system reliability in northwestern Ontario. Given the nature of the conversion, the Ministry of Energy (**"Ministry"**) recognizes OPG's requirement for a long-term energy supply contract in respect of the output from these units (the "**Agreement**"). As such, the Ministry has determined to pursue the initiative (the **"Initiative"**) of negotiating and concluding such an Agreement.

Direction

Therefore, I hereby direct the OPA to assume responsibility for exercising all powers and performing all duties of the Crown regarding the negotiation and conclusion of the Agreement with OPG. It is my expectation that the financial terms of the Agreement should be commercially reasonable for a facility being converted from coal to natural gas of the size and location of the Thunder Bay Generating Station. The Agreement should also provide an incentive to OPG to optimize the operation of the facility to reflect the hour-by-hour value of power to the Ontario electricity system.

The OPA will make reasonable efforts to complete the negotiations and execute the Agreement by December 31, 2011.

This direction is effective and binding as of the date hereof.

Sincerely,

Brad Duguid
Minister

ONTARIO POWER AUTHORITY

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Ministry Directive: Thunder Bay Generating Station Conversion to Natural Gas

Wed, 08/17/2011

Downloads:

Ministry Directive: Thunder Bay Generating Station Conversion to Natural Gas [1]

The Minister has directed the OPA [2]to assume responsibility of the Crown for negotiating and entering into a long-term energy supply contract (the "Agreement") with Ontario Power Generation (OPG) for the output from two generating units at OPG's Thunder Bay Generating Station once they are converted from coal to natural gas. The Minister has asked the Ontario Power Authority to endeavor to execute the Agreement by December 31, 2011.

News from OPA

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Source URL: http://www.powerauthority.ca/news/ministry-directive-thunder-bay-generating-station-conversion-natural-gas

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[2] http://www.powerauthority.ca/sites/default/files/new_files/about_us/pdfs/MC-2011-2974.pdf

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2, T1, Schedule 1, Page 21

When (in which year) does Union expect that OPG's Lambton and Nanticoke Gas conversion projects, the proposed Waterloo-Cambridge peaking facility, and the replacement for the "Oakville project", to start using natural gas? How does Union propose to deal with the very large increases in gas consumption, if they occur during the next five IRM years? What expenditures will be necessary on Union's part to serve each of the four planned gas facilities? How much capital and/or O&M is being forecast for each of the four gas plants in 2013?

Response:

The Lambton Generating Station is forecast to be in service by November 1, 2014, however, no Ministerial Directive has been issued to commence that project.

The timing of the Nanticoke Generating Station and the Cambridge Peaking facility are unknown. The capital and O&M associated with the Nanticoke and Cambridge projects are not known at this time.

For 2013, Union has included $1.8 million of capital related to the Lambton Generating Station.

Union is not aware of any proposals to replace the "Oakville project".

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: A2, T1, Schedule 1, Page 22

What are the estimated gas revenues from the test year and through next IRM years for gas transport to the St. Clair, East Windsor, and Halton Hills generation stations?

Response:

The forecast revenue for St Clair, East Windsor and Halton are $9.21 million for 2013 and $9.21 million for 2014. Union does not have a revenue forecast beyond 2014.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Can you provide the number of contracts and the volumes of gas under each contract to each shipper on the Dawn Parkway, and Dawn-Kirkwall lines that expire on November 1 of each of 2014, 2015, 2016, 2017, and 2018? Do most of the contracts take the form of annual contracts, renewable automatically, unless two years' notice of termination is provided, as described in the 2011 Annual Report, or are there variations? Please describe the types of variations from the model described above.

Response:

Contracts, volumes and expiry dates are information that is posted on the Union Gas website. This information is readily available through the Index of Customers which can be found at:
http://www.uniongas.com/storagetransportation/infopostings/transportcustomers.asp
The following excerpt details the number of contracts and the volumes of gas under each contract to each shipper on the Dawn Parkway, and Dawn-Kirkwall lines that expire in each of 2014, 2015, 2016, 2017, and 2018.

Dawn Kirkwall	# of contracts	End Date	Quantity (GJ)
	1	31-Mar-14	32,123
	3	31-Oct-14	13,336
			158,003
			35,806
	2	31-Oct-15	62,602
			38,306
	1	31-Oct-16	31,746
	1	31-Oct-17	10,791
	1	31-Oct-18	138,600

Dawn - Parkway	# of	End Date	Quantity
	2	31-Mar-14	11,322
			1,764,678
	5	31-Oct-14	10,692
			10,785
			2,113
			18,703
			15,000
	4	31-Mar-15	11,654
			88,728
			22,908
			52,343
	12	31-Oct-16	21,021
			11,809
			119,787
			4,000
			35,000
			43,837
			1,081
			44,019
			6,410
			21,825
			5,467
			55,123
	12	31-Oct-17	12,953
			17,162
			10,792
			9,282
			6,475
			2,158
			4,317
			18,077
			34,950
			43,116
			27,803
			6,333
	10	31-Oct-18	106,000
			17,351
			20,000
			7,500
			132,000
			9,170
			13,970
			30,217
			22,772
			20,560

It is confirmed that all of the contracts are renewable automatically with 2 years notice.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: C1, T1, page 3

Please provide, or provide a link to, the rate documentation for each of the four rates shown on Table 1.

Response:

Please see Exhibit H3, Tab 3, Schedule 1, Updated for Union's Rate Schedules.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: C1, T1, page 3

Why are the adjustments applying the NAL to Commercial Rates M1 and M2 in the opposite direction from one another? Please explain fully.

Response:

Union forecasts the M1 and M2 total consumption in aggregate and then allocates the forecasted consumption to the individual rate class groups based on historical volumetric share. An increase in volumetric share in one rate class group can result in a corresponding decrease in another rate class group. As a result, when comparing the commercial rate M1 and M2 to 2010 actuals, there is an opposing impact at the service class level.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: C1, T1, page 4

Are all of the commercial rate customers general services customers or are some contract customers? Please explain fully. Please explain the dividing line between contract customers and general service customers in functional terms, eg. type of load (residential, commercial, institutional, industrial, etc.) volumes or demand thresholds, other contractual requirements, types of pipe [pressure, thickness], etc. For example, are, or could, universities, large hospitals, or very large office buildings be contract customers? Please explain fully.

Response:

All commercial and industrial customers included in the General Service Demand Forecast, and in Table 1 in Exhibit C1, Tab 1, page 3, are non-contract customers.

The primary distinction between contract and non-contract (general service) customers is volume consumed. To be eligible to choose contract rate service, a customer must meet specified minimum volume thresholds which vary with the specific contract rate class. This minimum annual volume threshold is currently 700,000 m^3 per year. Union has proposed in this filing that the minimum threshold be reduced to 350,000 m^3 per year. Contract rates are not mandatory for customers who meet the contract qualifying consumption volumes; customers can elect to remain general service (non-contract) customers at their discretion. A full description of Union's rates and services can be found at http://www.uniongas.com/business/accountservices.

Union's contract rate categories do not distinguish between end use applications. Accordingly, contract rate customers within a specific rate class can come from a variety of market segments, including commercial, industrial, institutional and agricultural sectors as examples. The generally common characteristic of customers within a contract rate class is similar consumption profiles.

Union has several universities and hospitals that are contract customers and also has universities and hospitals who are general service customers.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: C1, T1, page 5, Lines 5-8

Please explain more completely the method for estimating commercial NAL estimates.

Response:

The basis for the forecast NAC estimate is econometric demand analysis combined with adjustments to reflect the impact on consumption of the DSM plan. Please see Exhibit C1, Tab 1, pp. 16 – 19 and pp. 21-22.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: C1, T1, page 13, Table V

Please provide 2011 actuals.

Response:

Please refer to the two residential tabs contained in the 2013 REGN DATA FILE Apr 2012 Excel file for the actual 2011 demand driver values for the residential market.

Line No.		2011
1	Southern (Act. HDD)	3,695.1
2	Northern (Act. HDD)	4,741.0
3	Furnace Efficiency Index (FEI)	0.892
4	Persons per Household (PPH)	2.70
5	Southern Total Bill Amount: $	898
6	Northern Total Bill Amount: $	1,023

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: C1, T1, pages 13 and 14, Table V

Please explain how the Energy Efficiency Index is calculated.

Response:

Please see the responses at Exhibit J.C-1-1-1 and Exhibit J.C-1-2-3 a).

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

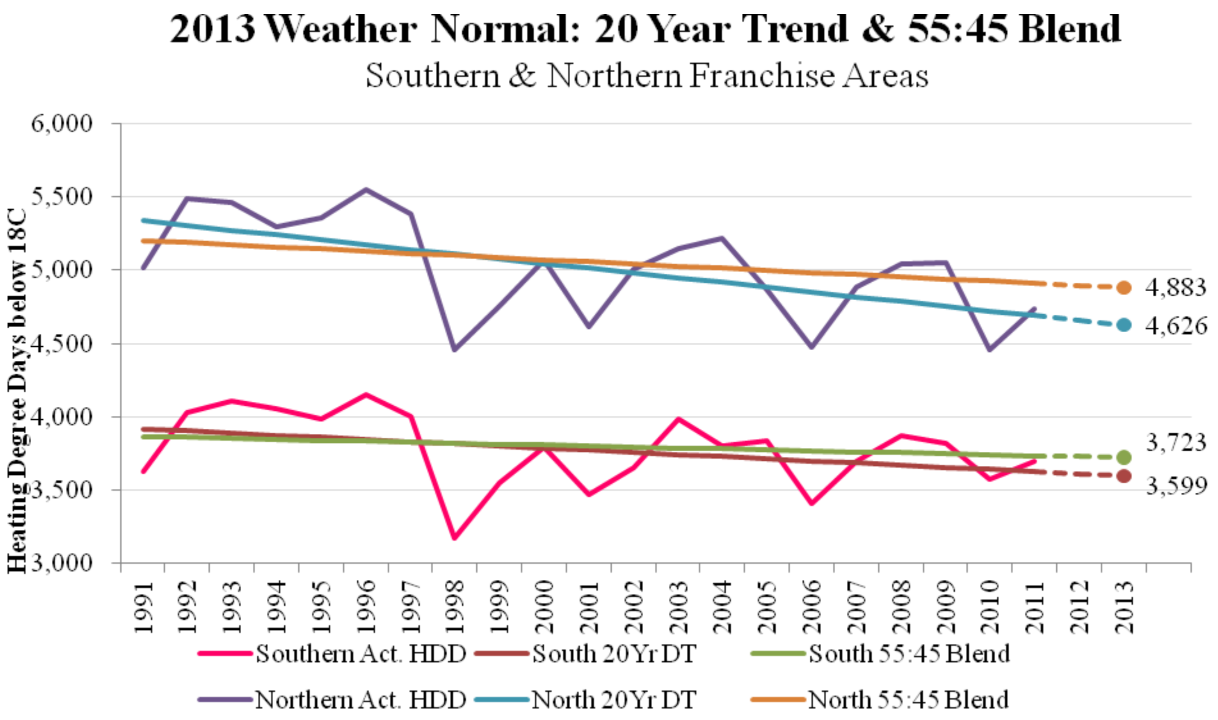
Ref: Exhibit C1, T1, page 14

Please show Table V and Figure 1 with the current weather normalization method.

Response:

The requested version of Figure1 is presented below. This chart shows the actual and the weather normals for the 20 year trend method (*shown originally in evidence*), and the current blended 55:45 normal method. The blended normal tracks above the 20 year trend normal estimates. This demonstrates the cold weather bias of the blended normal methodology.

In table 5 of the evidence, the estimated weather normal in 2013 when based on the blended 55:45 method, is the following: Southern 3,723 HDD and Northern 4,883 HDD. All other data presented on the table is provided in the responses to the question 10 and 11 stated above.



UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 5

a) Has Union investigated whether or not the current definition of a heating degree day (temperatures below 18^{o} C) is still the appropriate balance point for calculating heating degree days? If not, why not? If yes, please provide the results of the investigation.

b) Please provide all the data used to calculate the 20 year trend and 30 year average forecasts shown in Figure 1 in a live Excel spreadsheet. Please also provide all the equations used to forecast the 20 year average forecast figures shown in Figure 1, along with the associated regression statistics.

c) Please provide a similar figure for the Northern Region HDD forecasts as has been provided in Figure 1 for Toronto Pearson Airport. Please also provide all the data used to calculate the 20 year trend and 30 year average forecasts shown in the requested figure in a live Excel spreadsheet. Please also provide all the equations used to forecast the 20 year average forecast figures shown in Figure 1, along with the associated regression statistics.

d) Please provide the equations and regression statistics used by Union to forecast the 2013 South and North HDD forecasts.

e) Please confirm that the figures shown in Figure 1 are based on forecasts determined using data that ends 3 years in advance of the forecast period. For example, the 2010 forecasts are based on actual data up to and including 2007.

f) Is the data shown in Table 1 based on the Toronto Pearson Airport data shown in Figure 1? If yes, please provide a similar table that is based on the data used for the Northern Region.

g) Please provide a table similar to Table 1 that does the comparison of the 2 year ahead forecast, rather than the 3 year ahead forecast based on the Pearson Airport data and the Northern Region data.

h) Please provide the forecasts for the South, North and combined HDD for the 2011, 2012 and 2013 years that result from the methodology used by Union.

i) Please provide a copy of the source of the historical degree day information used to forecast the HDD forecasts for 2013.

j) Please explain and provide an example of how the annual HDD forecast is split into the monthly HDD forecasts used in the various use per customer and volumetric equations.

Response:

a) Union has not recently investigated whether or not the current definition of a heating degree-day (temperature below 18C) is still the appropriate balance point for calculating heating degree-days. The reasons for not investigating are:
   - The current balance point definition of 18 C for the Union normal was defined by the Ontario Energy Board in the previous Union Gas 2004 rate case; and
   - The current definition of 18C or 65F is an industry recognized standard.

b) Table 1 below provides the actual annual weather data for Toronto Pearson Airport. The forecast estimates for each methodology are shown in Table 2. A 3-year lag was recognized when the estimated normals were prepared. The estimates for the 30-year average methodology were obtained by using the simple average function. The estimates for the 20-year trend methodology were obtained by using the trend estimation function in the excel spreadsheet; individual regressions were not prepared. The blended methodology applied the 55% and 45% proportions to the HDD normal estimates obtained from the two other methods: 30-year average and 20-year trend.

Table 1
Toronto Pearson Airport: Annual Heating Degree-Days below 18C

	1940's	1950's	1960's	1970's	1980's	1990's	2000's	2010's
Year 0	4,562	4,163	4,013	4,309	4,382	3,636	3,826	3,465
Year 1	3,923	3,978	3,943	4,166	4,145	3,686	3,423	3,599
Year 2	3,987	3,836	4,105	4,572	4,187	4,112	3,631	
Year 3	4,453	3,622	4,125	3,947	4,066	4,181	4,064	
Year 4	4,113	3,957	4,168	4,236	4,144	4,110	3,862	
Year 5	4,283	3,890	4,359	4,005	4,109	4,042	3,797	
Year 6	3,801	4,181	4,263	4,475	3,987	4,177	3,379	
Year 7	4,153	3,895	4,310	4,181	3,765	4,034	3,719	
Year 8	4,125	4,051	4,309	4,485	4,076	3,219	3,836	
Year 9	3,810	4,025	4,291	4,236	4,246	3,541	3,836	

Note: shaded area indicates data used to estimate the normals

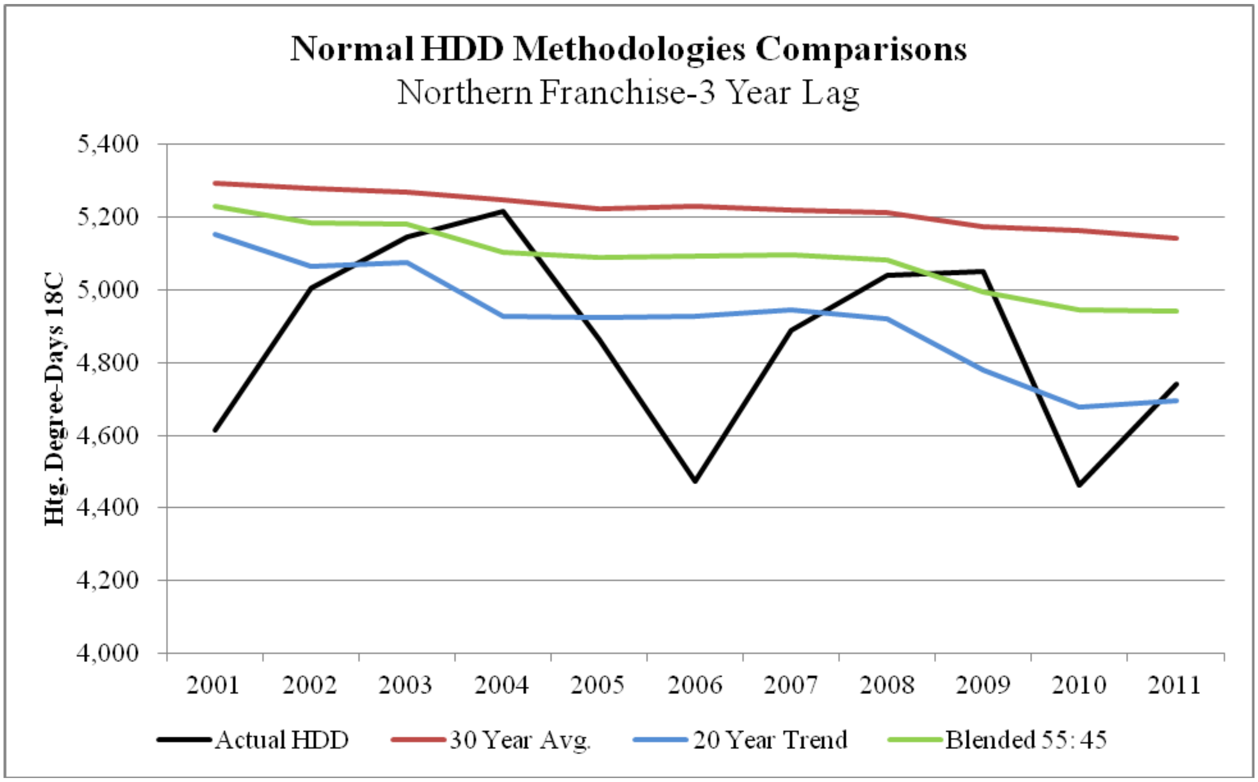
Table 2
Toronto Pearson Airport HDD

YEAR	ACTUAL	30 Yr. Avg.	20 Yr. Trend	55:45 Blend
1985	4,109	4,161	4,266	4,208
1986	3,987	4,176	4,203	4,188
1987	3,765	4,182	4,165	4,174
1988	4,076	4,189	4,147	4,170
1989	4,246	4,183	4,092	4,142
1990	3,636	4,179	3,999	4,098
1991	3,686	4,179	3,987	4,093
1992	4,112	4,187	4,015	4,109
1993	4,181	4,174	3,908	4,054
1994	4,110	4,166	3,803	4,002
1995	4,042	4,166	3,865	4,030
1996	4,177	4,168	3,859	4,029
1997	4,034	4,166	3,874	4,035
1998	3,219	4,155	3,843	4,015
1999	3,541	4,152	3,911	4,044
2000	3,826	4,143	3,909	4,038
2001	3,423	4,107	3,768	3,954
2002	3,631	4,082	3,688	3,905
2003	4,064	4,066	3,708	3,905
2004	3,862	4,041	3,610	3,847
2005	3,797	4,010	3,581	3,817
2006	3,379	4,014	3,642	3,847
2007	3,719	4,001	3,670	3,852
2008	3,836	3,994	3,682	3,854
2009	3,836	3,958	3,586	3,791
2010	3,465	3,942	3,548	3,765
2011	3,599	3,921	3,582	3,768

c) The chart for the northern franchise region presented below compares the actual weather with estimates produced by three normal weather methodologies assuming a 3-year regulatory lag.

Please note that the 20-year declining trend produces weather normal estimates that in most years are the closest to the actual weather. This is especially true in 2011. Both the 30-year average and the blended weather normal methodology well overshoot the actual weather and are biased to cold weather levels.

Please refer to the response provided at part b) above for a description of the weather normal estimation process.


Normal HDD Methodologies Comparisons
Northern Franchise-3 Year Lag
Htg. Degree-Days 18C
5,400
5,200
5,000
4,800
4,600
4,400
4,200
4,000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Actual HDD
30 Year Avg.
20 Year Trend
Blended 55:45

NORTHERN FRANCHISE Htg. Degree-Days below 18C

Year		Weather Normal Estimates with 3 Year Lag		
	Actual HDD	30-Year Avg.	20-Year Trend	Blended 55: 45
1969	5,121			
1970	5,414			
1971	5,274			
1972	5,742			
1973	4,941			
1974	5,446			
1975	5,134			
1976	5,643			
1977	5,188			
1978	5,640			
1979	5,458			
1980	5,559			
1981	5,092			
1982	5,430			
1983	5,195			
1984	5,175			
1985	5,438			
1986	5,175			
1987	4,722			
1988	5,317			
1989	5,654			
1990	4,994			
1991	5,019			
1992	5,489			
1993	5,460			
1994	5,294			
1995	5,358			
1996	5,550			
1997	5,384			
1998	4,457			
1999	4,754			
2000	5,065			
2001	4,613	5,292	5,151	5,229
2002	5,007	5,280	5,064	5,183
2003	5,147	5,268	5,077	5,182
2004	5,216	5,246	4,926	5,102
2005	4,866	5,222	4,925	5,088
2006	4,473	5,229	4,928	5,093
2007	4,888	5,221	4,946	5,097
2008	5,040	5,212	4,921	5,081
2009	5,049	5,173	4,779	4,995
2010	4,462	5,163	4,677	4,944
2011	4,741	5,143	4,696	4,942

d) The trend line statistics are:

Northern Normal = 5368.61 – (32.30 x YEAR)

R^2 = 30%   t-statistics = 38.96 and -2.81

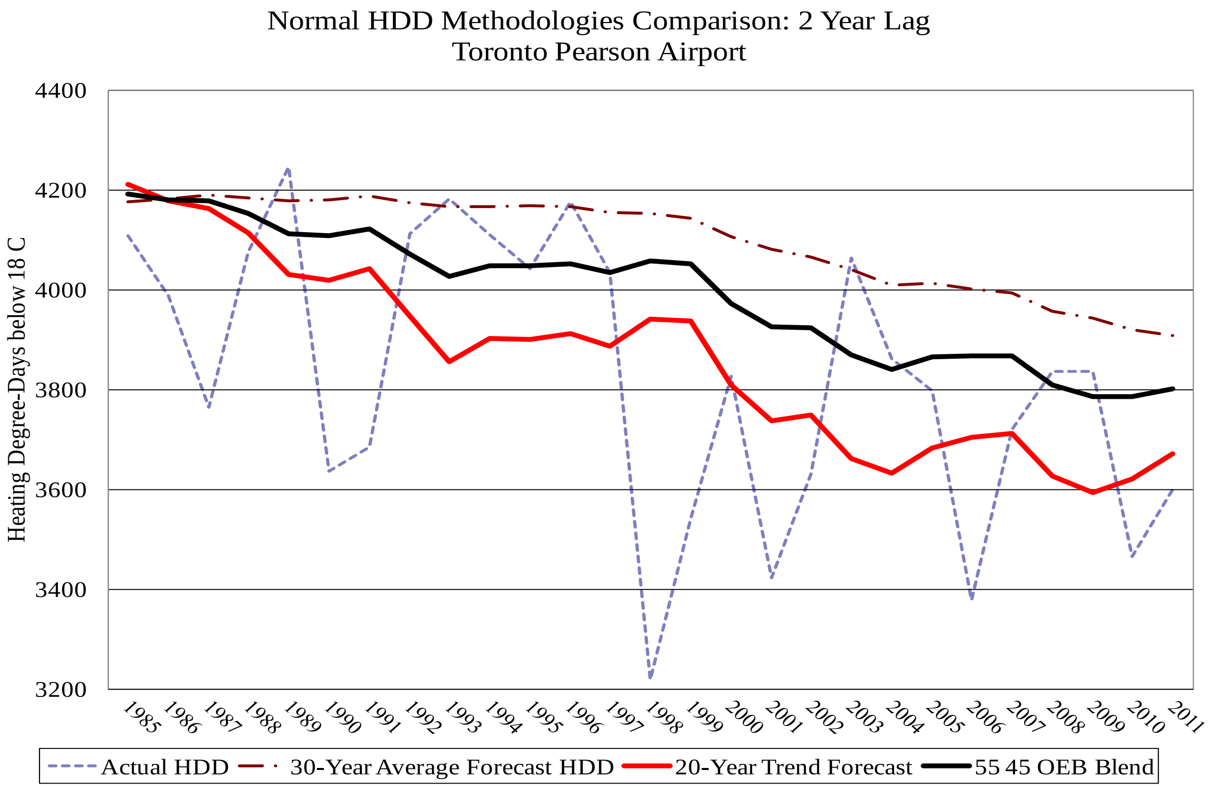
Southern Normal = 3933.18 – (14.53 x YEAR)

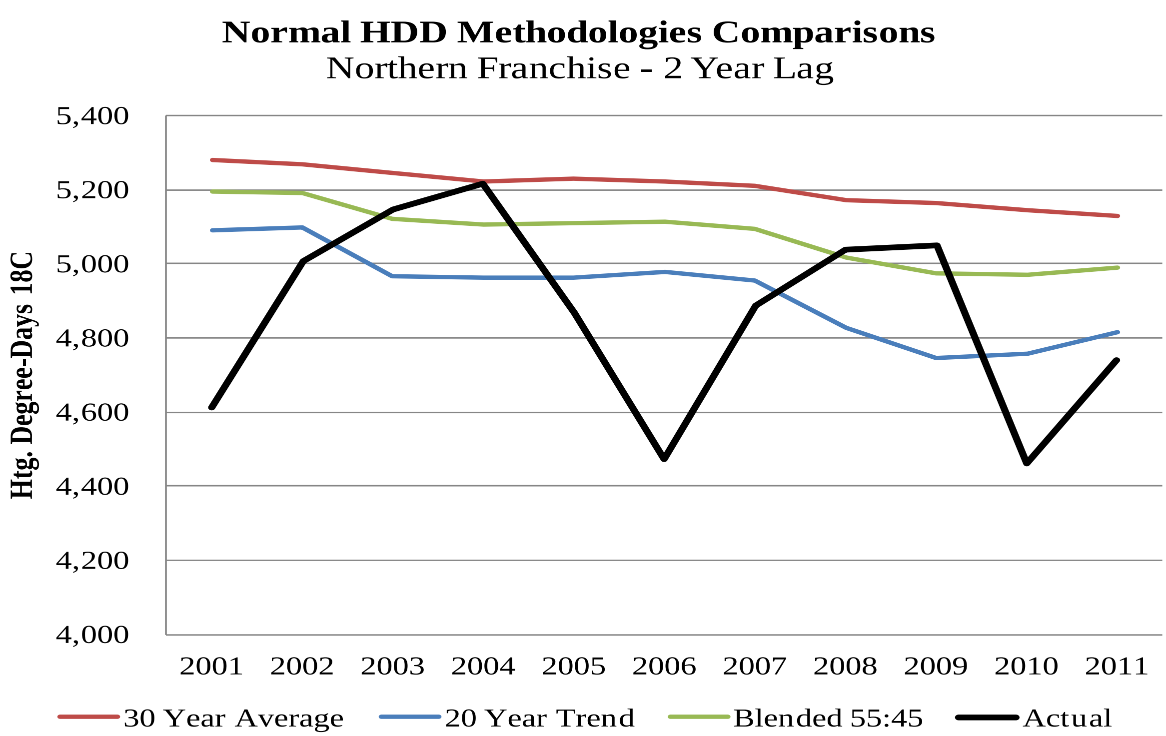
R^2 = 11%   t-statistics = 33.73 and -1.5

e) The forecasts in the original evidence incorporate a three year lag. A 3-year lag was used because the test year is 2013 and the actual weather data at the time the demand forecast was prepared spanned until the year 2010.

f) The normalized total volume data shown on table 1 is standardized according to the 2013 Union Gas weather normals for both the southern and northern franchise areas.

g) Please refer to the two charts below for Toronto Pearson Airport and northern franchise weather that incorporate a 2-year regulatory lag instead of a 3-year lag. The 2-year regulatory lag charts demonstrate once again the superiority of the 20-year declining trend weather normal methodology when compared to the current blended weather normal methodology. The estimates obtained by 20-year declining trend weather normal methodology pass though the middle of the actual weather data. The other methods do not provide symmetric results.


Normal HDD Methodologies Comparison: 2 Year Lag
Toronto Pearson Airport
Heating Degree-Days below 18 C
4400
4200
4000
3800
3600
3400
3200
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
Actual HDD
30-Year Average Forecast HDD
20-Year Trend Forecast
55 45 OEB Blend


Normal HDD Methodologies Comparisons
Northern Franchise - 2 Year Lag
Htg. Degree-Days 18C
5,400
5,200
5,000
4,800
4,600
4,400
4,200
4,000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
30 Year Average
20 Year Trend
Blended 55:45
Actual

h) The table below provides the estimated weather normal heating degree day estimates.

Year	Methodology	South	North	Total Company
2011	Blended 55:45	3775	4978	4075
2012	Blended 55:45	3751	4924	4045
2013	20 Year Trend	3599	4626	3856

i) The actual heating degree statistics for the period spanning the years 1971 to 2011 is contained in the 2013 REGN DATA FILE_Apr 2012 excel file in the Weather Union HDD tab.

j) The weather normal has two components: the 30-year average (55% weight) and the 20-year declining trend (45% weight). The monthly normals are obtained by applying the weights to the monthly estimates for each component as described below.

For the 30-year average component, the monthly HDD averages are calculated directly from the individual month weather statistics. For example for the year 2013, the 30-year average for the month of January is calculated according to reported data for January spanning the years 1981 to 2010. This calculation is performed on both regional franchise areas.

For the 20-year declining trend component, each monthly normal estimate is calculated by multiplying the annual normal estimate derived by the trend line by a seasonal percentage. The seasonal percentage for each month is the average over 20 years of its percent share of the annual heating degree-days. The seasonal percentages are calculated for each franchise area. For example for the year 2013, the 20-year trend HDD estimate for the southern franchise for the month of January is obtained by multiplying the 3,599 HDD estimate by 18.8%. The month of January had a seasonal percent share that averaged 18.8% in the southern franchise over the period 1991 to 2010.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 1, Figure 1

a) Please provide the Statistics for the 20 year declining trend line and the existing weather normal method.

b) Graph actual and the proposed 20 year declining trend and the current approved weather normal line on a Version of Figure 1. (larger scale) Discuss the differences.

Response:

a) and b) Please see the response at Exhibit J.C-1-3-2.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 5, Figure 1

a) Why is Pearson Airport Data comparison relevant to Union's Franchise?

b) Indicate where weather data are available in the Southern, Northern and Eastern Delivery Zones.

c) Please provide a summary of weather data for each zone and how this is used.

d) Please provide normalization analysis for each zone.

e) Demonstrate how the HDD for each zone is/is not correlated with Pearson Airport Data.

f) Are the Statistics reported in Table 1 for Pearson Airport or for the average of the three (2) franchise zones?

g) If not already provided above, please provide a similar figure for the Northern Region HDD forecasts as has been provided in Figure 1 for Toronto Pearson Airport. Provide the equations used to calculate the 20year trend and 30 year average forecasts, also the associated regression statistics.

h) Do the statistics change if 2011 data are included? Please provide an estimate.

i) Could the data and HDD analysis be influenced by other (excluded) Weather variables including Wind speed/wind chill?

j) Has Union done any assessments of other variables, using data from either Pearson Airport or other locations, including Wind Speed data?

k) Please update the forecast and Summary Schedule 1 to include 2011 results.

Response:

a) In Union's 2004 rate case (RP-2003-0063) Pearson Airport was selected as the weather data site for the 20-year trend weather normal methodology. This site has the following features:
   1) A central location with weather data going back to the mid 1950's;

2) Toronto Pearson heating degree-day weather data from the 1985 to 2011 is highly correlated with weather data for the southern (98%) and northern (95%) franchise areas.

b) Please refer the 2013 REGN DATA File_Apr 2012 Excel file; please see the Weather Union HDD tab.

c) Please refer the 2013 REGN DATA File_Apr 2012 Excel file; please see the Weather Union HDD tab. This weather data is trended by the 20-year trend weather normal methodology and projected to 2013. See 20 Yr Trend Normal tab.

d) Please see Exhibit C1, Tab 1, Updated, Table 4.

e) Please see the response at a) above.

f) The table presents statistical test results for estimated weather normals based upon Toronto Pearson Airport weather data.

g) Please see the Weather Union HDD tab in the 2013 REGN DATA File_Apr 2012 Excel file.

h) The weather normal estimates for 2013 change when the 20-year trend estimate includes the 2011 actual weather data and drops the 1981 data. For the southern region the 3,599 HDD estimate becomes 3,576 HDD, a decline of 0.6%. For the northern region the 4,626 HDD becomes 4,595 HDD, a decline of 0.7%.

i) Energy demand forecasting for the general service market uses recorded heating degree day data. Wind chill, cloud cover, precipitation related weather data have been examined but were not strongly correlated. The greater variability present in wind (both speed and direction) and cloud cover means that these weather characteristics are relatively local and vary greatly over time and across set geographic areas. Heating degree-days are proven, reliable and dependable predictors of energy demand.

j) Yes, Union has examined different weather variables such as wind speed but could not find a strong correlation. Union also examined effective balance point heating degree days but the marginal increase in accuracy did not warrant the increased complexity and administration.

k) Please see the table below. Bold figures indicate best results. The 20 year declining trend methodology exhibits superior results for all three accuracy tests: RMSE, average variance from actual and mean percent error.

Weather Normal Forecast Estimate versus Actual Annual Level
26 Observations estimates for 1985 to 2011 inclusive

Error Measure	30 Yr. Avg.	20 Yr. DT	55:45 Blend
Root Mean Square: RMSE	373	**264**	303
Avg. Variance from Actual	278	**55**	177
Std. Deviation of Variance	254	264	250
Mean Percent Error	(7.8%)	**(1.8%)**	(5.1%)

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Ref: C1 T5

a) Please provide the sources for the HDD data used for the North and South Operating Areas.

b) Please indicate which particular statistical software package(s) was used for the 20 year declining trend regression.

c) Please provide all maintained assumptions regarding the error generating mechanism in the selected model, i.e. is it assumed that the errors are independent and identically distributed normally with zero mean and constant variance?

d) Were any alternatives – such as a 10-year linear trend or a Box-Jenkins or ARIMA formulation or non-linear regression – other than the 20-year declining trend, 30-year average considered, and the currently approved 55:45 hybrid model, considered and tested by Union?

e) Was the time series data used in the 20-year trend method tested for stationarity? If so, please provide the test results; if not, why not?

f) Did Union transform the data in any way to address problems associated with non-stationarity? If so, please explain how; if not, why not?

g) Did Union test for any violations of the standard assumptions underpinning the use of linear regression such as heteroskedasticity or autocorrelation? If so, please provide full details; if not, why not?

h) Please provide scatterplots of the residuals for each regression underpinning the 2013 forecast demand.

i) Did Union use all available HDD data in its 2013 forecast?

j) If not provided elsewhere, please provide the F-statistics for assumptions an each regression underpinning the 2013 forecast demand.

k) What would be the impact on the 2013 revenue deficiency if the Board ordered that the currently approved forecasting methodology be retained?

Response:

a) Please refer to the 2013 REGN DATA FILE Apr 2012 excel file for the actual weather data. This file contains the southern, northern and total company historic weather data. The Union HDD data is tabled in the tab called Union Weather HDD.

Union subscribes to an electronic weather service that provides daily heating degree day data collected by Environment Canada for 16 weather stations located across the southern and northern franchise area. The southern franchise HDD data is a weighed average of the data for: Windsor, Sarnia, London, Delhi, Waterloo and Hamilton. The northern franchise HDD data is a weighed average of the data for: International Falls, Thunder Bay, Sault Sainte Marie, North Bay, Sudbury, Kapuskasing, Timmins, Muskoka and Trenton. Weights are applied to the data for each station to obtain the regional weather data series.

b) Union used the Excel spreadsheet trend function for numerical estimates and the linear trend function in the graphical charting menu.

c) The methodology is not premised on the merits of regression analysis and associated statistical regression test results. These standard tests regarding independent randomly distributed errors are not the basis for the methodology. Consequently no such regression related tests and residual plots are examined when setting the weather normal trend line.

Accuracy is the key merit of the methodology. Compared to other methodologies the 20-year trend method minimizes the forecast error between the actual and forecast HDD estimate for the test year.

d) Box Jenkins or ARIMA were not examined or tested. In the 2004 rate case (RP-2003-0063) the Union's weather evidence discussed 7 methodologies. They were:

1. 30-year average – the Union Gas legacy normalization prior to 2004;
2. 30-year trend – the prototype trend methodology;
3. 20-year trend – the recommended methodology;
4. 15-year trend with 5-year forecast information – requires external long range weather forecast;
5. Variable year weighted average trend (Leo de Bever) – this was Enbridge's normal methodology for the Greater Toronto Area which was replaced with the 20-year trend methodology;
6. 20-year average – a comparator to the trend; and,
7. 10-year average – short time or more recent period.

The merit and benefits of the 20-year trend methodology are the following:

- The methodology directionally reflects the observed climate change or global warming phenomenon;

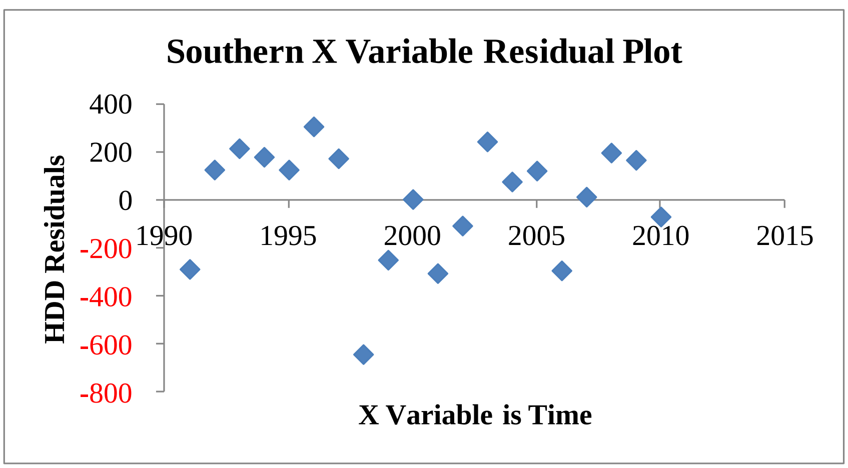
- The methodology when compared to other methods has superior forecast accuracy as indicated by several forecast error measurements: root mean square error (RMSE), mean percent error (MPE) and the average deviation from actual;
- The methodology yields a weather normal estimate with symmetric upside and down side risks;
- The methodology is simple to administer, understand and demonstrate graphically; and
- The test of time demonstrates that it is superior to the 30-year average and the current blended methodology. Figure 1 on page 3 of Exhibit C1, Tab 5 of the evidence and several charts contained the tab named Actual Weather vs. Normal of the 2013 REGN DATA File Apr 2012 excel file clearly illustrates this fact.

e) No. See the response at c) above.

f) No. See the response at c) above.

g) No. See the response at c) above.

h) A residual plot for the southern franchise area is presented below. Analysis of residuals, as discussed in the response at c) above, is not the basis for the proposal to use the 20-year trend methodology.



i) The 20-year trend normal requires 20 years of historical HDD data. Union used the annual HDD data for the southern and northern franchise areas spanning the years 1980 to 2010 in the original evidence and 1981 to 2011 in the update for the year 2011 to set the weather normal estimates.

j) The appendix A in Exhibit C1 Tab 1 contains the following F statistics:

1) Table 5 on page 8 has the residential equation F test results;
2) Table 6 on page 11 has the commercial equation F test results; and,

3) Table 7 on page 14 has the industrial equation F test results.

k) The impact on the revenue deficiency if the Board ordered the use of currently approved weather normal methodology would be to decrease the revenue deficiency by approximately $7 million at current April 2012 rates.

UNION GAS LIMITED

Answer to Interrogatory from
School Energy Coalition ("SEC")

Ref: Exhibit A3, Tab 1, Schedule 5

Please advise which weather methodology was used for the 2012 Forecast.

Response:

The 2012 demand and revenue forecast estimates assume the blended 55:45 weather normal.

UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

Ref: C1, T1, pages 3 and 6

Please reproduce Tables 1 and 2 using the currently approved normalization method, rather than Union's new proposal in this application. Why is the same pattern repeated as between the .01 and 10. commercial rates, except for a very small decimal adjustment for 01 compared with M2?

Response:

Please see revised Tables 1 and 2 below using the currently approved normalization method.

Table 1 according to Blended 55:45 Normal for 2013
Change in Total Throughput Volumes: 10^3 m^3
2011 TO 2013

Line No.	Rate & Service Customer Class	Total W.N. [1] Throughput 2011	Change in volume due to: Customer Growth	DSM Plan	HFO & FX Rate effect	NAC Decline	Total Forecast Throughput 2013	Total Change
1	Residential Rate M1	2,204,972	64,944	(12,845)		(102,998)	2,154,073	(50,899)
2	Residential Rate M2	4,114	318	(24)		(705)	3,703	(410)
3	Residential Rate 01	673,307	19,990	(1,821)		(34,493)	656,983	(16,324)
4	Commercial Rate M1	641,615	5,977	(8,407)		92,507	731,693	90,078
5	Commercial Rate M2	789,299	22,152	(10,342)		(179,488)	621,621	(167,678)
6	Tobacco Rate M1	13,106	53	-		(3,180)	9,979	(3,127)
7	Tobacco Rate M2	5,444	(2,604)	-		(884)	1,956	(3,488)
8	Commercial Rate 01	245,168	5,033	(2,725)		(15,565)	231,911	(13,257)
9	Commercial Rate 10	256,537	(10,563)	(2,942)		(9,690)	233,343	(23,195)
10	Industrial Rate M1	57,439	(708)	(484)	(422)	4,412	60,237	2,799
11	Industrial Rate M2	339,314	14,881	(2,856)	(5,363)	7,297	353,273	13,959
12	Industrial Rate 10	48,589	(4,335)	(238)	(662)	(3,693)	39,662	(8,927)
13	Industrial L.I.B, Rate 10	40,808	8,989	(238)	(803)	2,420	51,177	10,369
		5,319,712	124,127	(42,921)	(7,249)	(244,059)	5,149,610	(170,102)
			2.3%	-0.8%	-0.1%	-4.6%	-3.2%	-3.2%
	--- service class summary ---							
14	Residential	2,882,393	85,252	(14,690)	-	(138,196)	2,814,759	(67,634)
15	Commercial	1,951,169	20,048	(24,416)	-	(116,299)	1,830,502	(120,667)
16	Industrial	486,150	18,827	(3,816)	(7,249)	10,436	504,349	18,199

[1] The 2011 Actual throughput volumes are weather normalized according to the 2013 weather normal based upon the 55:45 blended weather normal methodology

Table 2 according to Blended 55:45 Normal for 2013
Change in Total Throughput Volumes: 10^3 m^3
2007 TO 2011

Line No.	Rate & Service Customer Class	Total W.N. [1] Throughput 2007	Change in volume due to Customer Growth	DSM Plan	HFO & FX Rate effect	NAC Decline	Total W.N. [1] Throughput 2011	Total Change
1	Residential Old Rate M2	2,203,403	126,552	(19,865)		(101,004)	2,209,086	5,682
2	Residential Rate 01	665,934	35,898	(4,006)		(24,519)	673,307	7,373
3	Commercial Old Rate M2	1,321,104	41,454	(39,729)		108,084	1,430,913	109,809
4	Tobacco Old Rate M2	15,353	(2,319)			5,517	18,550	3,198
5	Commercial Rate 01	213,783	12,149	(4,004)		23,241	245,168	31,385
6	Commercial Rate 10	240,735	(74,272)	(3,924)		93,999	256,537	15,803
7	Industrial Old Rate M2	444,239	(5,728)	(7,587)	22,766	(56,939)	396,753	(47,486)
8	Industrial Rate 10 [2]	44,322	(16,421)	(3,526)	2,252	21,962	48,589	4,267
9	Industrial L.I.B, Rate 10 [2]	79,932	(55,579)	(2,983)	4,069	15,369	40,808	(39,124)
10	Total	5,228,804	61,735	(85,623)	29,087	85,710	5,319,712	90,908
			1.2%	-1.6%	0.6%	1.6%	1.7%	1.7%
	--- service class summary ---							
11	Residential	2,869,337	162,450	(23,871)	-	(125,523)	2,882,393	13,056
12	Commercial	1,790,974	(22,988)	(47,657)	-	230,840	1,951,169	160,195
13	Industrial	568,493	(77,727)	(14,095)	29,087	(19,607)	486,150	(82,343)

[1] The 2011 Actual throughput volumes are weather normalized according to the 2013 weather normal based upon the 55:45 blended weather normal methodology

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit C1, Tab 2, page11

Forecasting Accuracy: Please provide the Actual Throughput Volumes vs. Forecasted Throughput Volume data for the Total Contract Demand & Wholesale market for the years 2008, 2009 and 2010.

Response:

The table below compares actual to forecast volume from 2007 through 2011.

Forecast to Actual Volume Comparison (10^6m^3)

Market		2007	2008	2009	2010	2011
Power	Forecast	1,805	1,944	2,092	2,064	2,066
	Actuals	2,078	1,659	1,854	2,349	2,463
	Variance	*273*	*-286*	*-238*	*285*	*397*
Steel/Chem/Ref	Forecast	3,416	3,357	3,888	3,366	3,659
	Actuals	3,272	3,523	2,971	3,271	3,582
	Variance	*-144*	*166*	*-917*	*-95*	*-77*
LCI/Key	Forecast	2,876	2,825	2,682	2,184	2,059
	Actuals	2,806	2,697	2,218	2,163	2,180
	Variance	*-70*	*-128*	*-464*	*-21*	*121*
Greenhouse	Forecast	153	148	221	188	198
	Actuals	173	203	197	246	287
	Variance	*20*	*55*	*-24*	*58*	*88*
Wholesale	Forecast	346	314	345	318	318
	Actuals	296	305	319	315	324
	Variance	*-50*	*-9*	*-26*	*-3*	*6*
Grand Total	**Forecast**	**8,596**	**8,588**	**9,229**	**8,120**	**8,301**
	Actuals	**8,625**	**8,386**	**7,560**	**8,344**	**8,836**
	Variance	***29***	***-202***	***-1,669***	***224***	***535***

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit C1, Tab 2, page 11

A comparison of the 2011 outlook filed in November 2011 and the update of March 27, 2012 with the actual data reveals that the volume throughput has been under forecasted across all rate classes (100, 20, 25, T1, M7, M4, M5). The error as compared to actuals is 4.2%.

a) Please provide reasons for the under forecast in throughput for 2011.

b) Please explain why the throughput is expected to decline for all rate classes apart from M5 in 2013 as compared to 2011.

Response:

The table below compares the volume variances, actual for 2011 to outlook for 2011.

Comparison 2011 Actual vs 2011 Outlook Volumes (10^6m^3)

Line No.		**Actual**	**Forecast**	**Variance**	**% Variance**	**% of Total Variance**
1	100	1,893	1,732.0	160.7	9.3%	45.6%
2	20	646	586.0	59.9	10.2%	17.0%
3	25	157	145.0	12.3	8.5%	3.5%
4	T1	4,607	4,608.0	-1.5	0.0%	-0.4%
5	M7	259	202.0	56.4	27.9%	16.0%
6	M4	442	398.0	44.3	11.1%	12.6%
7	M5	509	489.0	19.8	4.0%	5.6%
8	Other	324	324.0	0.3	0.1%	0.1%
9	**Total**	**8,837**	**8,484.0**	**352.2**		

a) The positive variance in Rate 100, Rate 20, Rate 25 and Rate M4 volumes between actual and forecast are driven by increased production at customer sites above the original forecast. The variance between forecast and actual volumes for Rate M7, are the result of a customer remaining on Rate M7 when they were originally forecast to change rate classes. The positive variance in Rate M5 is a result of incremental greenhouse growth.

b) The Rate T1 and Rate 100 show an increase in 2012 forecast throughput volumes as compared to 2011 followed by a decline in 2013. This is attributable to forecast contract parameter changes. Rate 25 throughput declines are a result of lower forecast production specifically in the power market.

Rate 20 show a decrease in 2012 throughput with a modest increase in 2013. This is the result of an unforecast production improvement in 2011 is attributable to resolution of a long standing labour dispute. This issue was not forecast to be resolved until the later part of 2012. Additionally authorized overrun in the power market that occurred in 2011 is not forecast for 2012 or 2013.

The reduction in Rate M7 volumes reflects the contractual changes that were expected in late 2010 and did not occur, and subsequently went into place late 2011.

Rate M4 declines reflect the expectation of lower customers in this rate class consistent with the historic trends.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 2, Original & Updated

a) Please explain the increase of about 4.1% in the volumes in Table 1 and the corresponding 2.8% increase in revenues in Table 2 between the forecast for 2011 and the actual 2011 figures. Does this reflect a stronger than expected economic recovery? If not, what does it reflect?

b) How many months of actual data was included in the original 2011 forecast?

Response:

a) The variances are explained by the following:

   1) The positive variance in 2011 power market volumes and revenue is driven by discretionary increases in generating facility operations over forecast at two generating sites, partly motivated by favourable pricing of natural gas over coal during this period;

   2) The positive variance in the Steel Chemical/refinery sector is attributable primarily to one facility operating an on-site cogeneration facility at a much higher frequency rate than forecast; and,

   3) The positive LCI/Key sector variance is primarily due to one customer's facility re-starting full operations from a long term work stoppage earlier than forecast. The positive variance in the greenhouse market is a result of increased production generally, plus incremental growth coming on-line earlier than forecast.

The table below summarizes both the revenue and volume variance by market sector with explanation following the table.

2011 Actual vs Forecast Revenues ($ millions)					
	Actual	**Forecast**	Variance	% Variance	% of Total Variance
Power	32.7	30.7	2.0	6.6%	62.8%
Steel/Chem/Ref	38.4	37.6	0.8	2.2%	25.2%
LCI/Key	36.4	36.1	0.3	0.8%	9.1%
Greenhouse	6.3	6.1	0.2	2.7%	5.1%
Wholesale	5.5	5.6	-0.1	-1.2%	-2.1%
Total	**119.3**	**116.1**	**3.2**		
2011 Actual vs Forecast Volumes (10^3m^3)					
	Actual	**Forecast**	Variance	% Variance	% of Total Variance
Power	2,464	2,231	233	10.4%	66.2%
Steel/Chem/Ref	3,582	3,553	30	0.8%	8.4%
LCI/Key	2,180	2,125	55	2.6%	15.6%
Greenhouse	287	252	35	13.7%	9.8%
Wholesale	324	324	0	0.0%	0.0%
Total	**8,837**	**8,485**	**352**	4.2%	

b) There are three months of actual and nine months of forecast data in the 2011 Outlook.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 2, Figure 1, Updated

Please explain the reduction in the forecast for power generation in 2012 and 2013 as compared to both the growth experienced between 2007 and 2011 and the level shown for 2011.

Response:

The net growth in power generation revenues from 2007 to 2011 of $6.04 million primarily reflects the development of three Clean Energy Supply ("CES") gas fired generation projects in Union's franchise area offset by a reduction in Lennox and the four South Rate T1 power generators. The 2011 versus 2007 variance by components is as follows:

	Revenue ($ Millions)	Volume (10^6)
North NUGs	0.33	129.4
South Rate T1	(0.66)	(256.4)
Lennox	(4.38)	(161.1)
CES	10.74	660.3
Total	6.04	372.3

The 2012 forecast is less than 2011 actuals by approximately $3.12 million. A contractual change relating to minimum annual volume and decreased customer consumption expectations drove the revenue reduction for the North NUGs. Changes in South revenue were also driven by forecast changes based on customer discussions regarding their consumption expectations. No Rate 25 volumes were forecast for Lennox or authorized overrun for the CES group. The variance for 2012 forecast revenue versus 2011 actuals is as follows:

	Revenue ($ Millions)	Volume (10^6)
North NUGs	(0.11)	(74.1)
South Rate T1	(0.29)	59.2
Lennox	(0.93)	(31.9)
CES	(1.79)	(200.0)
Total	(3.12)	(246.8)

*South Rate T1 excludes the 3 CES Rate T1 customers.

The 2013 forecast is less than 2011 actuals by approximately $3.26 million. The net incremental revenue decrease of approximately $100,000 from the comparison of 2011 actuals to 2012 forecast is driven by relatively small forecast variances in both North and South accounts in addition to one customer who expects to change rate classes in 2013. The variance for 2013 forecast revenue versus 2011 actuals is as follows:

	Revenue ($ Millions)	Volume (10^6)
North NUGs	(0.25)	(105.6)
South Rate T1	(0.35)	59.2
Lennox	(0.93)	(31.9)
CES	(1.73)	(195.0)
Total	(3.26)	(273.3)

*South Rate T1 excludes the 3 CES Rate T1 customers.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 2, page 14, Updated

Has Union included any volumes, revenues, capital expenditures and/or OM&A costs in the 2013 revenue requirement associated with the conversion of coal facilities at Nanticoke or Lambton or the peaking facility in the Waterloo-Cambridge area? If yes, please provide the details including the net impact on the 2013 revenue requirement.

Response:

No volumes, revenues, capital expenditures or OM&A costs have been included in the revenue requirement associated with the conversion of Nanticoke, or Waterloo-Cambridge

With respect to Lambton, there is forecast capital of $1.8 million for 2013. As the Lambton Generation Station is not forecast to be in service until November 2014, there is no impact on 2013 rates.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 2, Appendix A

a) Please explain how the HDD variable has been calculated for the total company franchise area based on the north and south HDD variables used in the general service volume equations.

b) Please update the equations by including actual data for 2011. Please provide the regression analysis summary output provided in Tables 1 and 2. Please provide the resulting forecasts for 2012 and 2013 in the same format as shown in Tables 1 and 2 in Exhibit C1, Tab 2, Updated.

c) Please provide all of the data (actual and forecast) used to estimate the equations in Tables 1 and 2 in a live Excel spreadsheet. Please include actual 2011 data in the spreadsheet.

Response:

a) The total company HDD weather variable is obtained by blending the southern and northern HDD values according to a ratio of 75:25 respectively. This blend is applied to all months and to actuals and forecast estimates. The total company weather data was applied to the LCI market because the customer accounts are located across the entire franchise area.

b) Please see the 2013 REGN DATA FILE_Apr 2012 Excel file for the actual data for the regression demand variables for the LCI and Green House contract rate markets.

   Please see the 2013 REGN RESULTS 2011 UPDATE_Apr 2012 Excel file for tabs presenting the regression results for the LCI and Greenhouse markets.

   The updated regressions result in the following updated total volume estimates (10^3m^3) for 2012 and 2013 for each market which are tabled below:

Year	LCI Mkt.	Greenhouse Mkt.
2012	1,062,850	315,930
2013	1,016,455	319,391

c) Please see the response at b) above.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 2, Updated

a) How are the volumes by sector shown in Table 1 translated into volumes by rate class in Table 3 for the non T1 and 100 rate customers? Please explain why the M4 volumes are forecast to decline in 2013 as compared to 2012, while the M5 volumes are forecast to increase.

b) How are the revenues calculated for each of the rate classes in terms of the volumes, contract demands and fixed customer charges? For example, please show how the forecast of $10.8 million for Rate M4 in 2013 shown in Table 4 has been derived based on volume forecast of 380 $10^6 m^3$ shown in Table 3.

c) Please provide a table in the same level of detail as Table 3 that shows this historical (including 2011) and forecast contract demand levels.

d) Does the Wholesale/REM forecasts reflect the increase in the distribution contract demand associated with an ethanol plant at one of the wholesale accounts?

Response:

a) Union has consumption information for each customer in all the market sectors. Market sector customers and their respective volumes are mapped to each rate class.

   The forecast decline in the Rate M4 rate class volumes in 2013 from 2012 is attributable to:
   i) A lower 2013 weather normal compared to 2012; and,
   ii) The continued decline in the number of accounts and output in the moderate-sized manufacturing and commercial areas of the economy like automotive, institutional and agriculture.

   The Rate M5 rate class has a heavy concentration of greenhouse customers, an area of the economy that is showing growth in the forecast period.

b) Union maintains monthly volume and daily load information on each contract account. Each account is contracted for specified demand, storage, volumetric and other requirements at the applicable rate class. These contract billing units are multiplied by the Board-approved rates within that class. The detailed break-out of how the forecast of $10.8 million of revenue has been derived on a volume forecast of 380 $10^6 m^3$ is presented in the table below.

			A	*B*	*A*B*
M4 2013 Forecast	Revenue Charge	Tier	Usage	Rates	Revenue
Demand Charges	Minimum Annual Volume Deficiency Charge		4,549	11.66	53,054
	Monthly Demand Charge	1	10,579	454.29	4,805,951
		2	7,864	197.10	1,549,912
		3	4,507	163.68	737,747
Demand Charges Total			27,499		7,146,665
Volumetric Charges	Monthly Delivery Commodity Charge	1	282,715	8.53	2,410,149
		2	82,082	8.53	699,750
		3	3,611	3.57	12,883
	Unauthorized Overrun Charge - Delivery		12,044	47.42	571,104
Volumetric Charges Total			380,452		3,693,887
			380,452		10,840,552

c)

Contract Demands by Rate Class in the Contract Market
For month ending December 31
10^3m^3

Rate	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 C12-14 Forecast	2013 C12-14 Forecast
100	7,181	6,234	5,858	5,977	6,006	6,215	5,293
20	2,408	3,431	3,338	3,338	3,231	3,412	4,288
T1	14,776	17,643	19,802	20,193	20,729	22,041	22,011
M7	2,509	2,433	1,614	1,619	1,235	1,185	1,185
M4	2,484	2,337	1,962	1,875	1,965	1,961	1,863
M5	152	106	99	60	46	52	52
Other	2,783	2,891	2,891	2,891	2,683	2,683	2,683
Grand Total	32,292	35,075	35,565	35,952	35,893	37,550	37,375

Note: No firm contract demand exists in Rate 25.

d) Yes.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 2 and Tables 1-4 and Appendix A (Contract demand)

a) Has the contract demand forecast methodology (in use since 2008) been approved by the Board?

b) If so, point to or provide a copy of the evidence supporting the approval.

c) If not, provide details on methodology, including data sources equation(s) weighting, coefficients, results and forecast error.

d) Please update Tables 1-4 for 2011 and provide a separate comparison of forecast (outlook) vs actual for each market segment. Discuss the differences.

e) Has the 2011 data been incorporated into Appendix A Table 1.? If so, please provide a copy.

Response:

a) Union has not requested Board approval of its contract demand forecast methodology.

b) Please see the response to a) above.

c) The data sources for the regression analysis for the LCI and Green House contract rate markets is contained in the 2013 REGN DATA FILE_April 2012 excel file. The historic demand variable data is tabled in a tabs called LCI Regn and Greenhouse Regn. The regression analysis for the original evidence is shown in Exhibit C1, Tab 2, Appendix A. The 2013 REGN RESULTS 2011 UPDATE excel file presents the updated regression results for both markets.

   Union is asking the Board to review and approve the contract rate class demand forecasts. In this application, the LCI and Greenhouse market segments in the contract rate market have been prepared by econometric methods, as has the General Service market, while the larger power and industrial market customers forecasts (Rate 100 and Rate T1) have been developed by using the bottom-up forecast approach.

   Econometric methods are one of many forecasting tools that can be used to forecast energy demand in the small to mid-size commercial and industrial marketplace. Other forecasting tools available to estimate demand include bottom up forecasting, trending and surveys.

Econometric methods are being applied because these two market segments exhibit characteristics that enable regression analysis. The main characteristics are:

- Sufficiently large customer populations
- Presence of stable seasonal trends
- Demand sensitivity to economic demand variables such as exchange rates and energy prices
- Robust regression results

d) Please see the responses at Exhibits J.C-3-1-2 and J.C-3-2-1 a) for a description of the differences.

e) No, the data has not been incorporated into Appendix A, Table 1.

UNION GAS LIMITED

Answer to Interrogatory from TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Summary Schedule 1

a) Please provide a version of this schedule that shows throughput volume by service type and rate class excluding power generation volumes.

b) Please provide a table showing total weather normal throughput volume (a) excluding power generation volumes, (b) power generation volumes only and (c) the total throughput (corresponding to the total shown on line no. 24) for each year shown on Summary Schedule 1.

Response:

a) Please see Attachment 1.

b)

Weather Normal Throughput Volume

Volume Throughput (10^6m^3)	2007 actual	2008 actual	2009 actual	2010 actual	2011 actual	2012 forecast	2013 forecast
Without Power Volumes	11,927	12,058	10,922	11,182	11,739	12,402	12,032
Power Volumes Only	2,078	1,659	1,854	2,349	2,463	2,215	2,189
Total	14,005	13,717	12,776	13,531	14,202	14,617	14,221

Total Weather Normal Throughput Volume by Service Type and Rate Class (1) without Power volumes
Year Ended December 31

Line No.	Particulars (10^6m^3)	Actual 2007 (b)	2008 (c)	2009 (d)	2010 (e)	2011 (f)	Forecast 2012 (g)	Forecast 2013 (h)
	General Service							
1	Rate M1 Firm	-	2,950	2,874	2,875	2,948	2,985	2,876
2	Rate M2 Firm	4,100	1,104	1,085	1,067	1,142	988	957
3	Rate 01 Firm	912	917	908	906	927	897	856
4	Rate 10 Firm	373	357	350	338	347	327	316
5	Total General Service	5,385	5,327	5,217	5,186	5,364	5,196	5,005
	Wholesale - Utility (2)							
6	Rate M9 Firm	20	31	55	61	60	60	61
7	Rate M10 Firm	0	0	0	0	0	0	0
8	Rate 77 Firm	-	-	-	-	-	-	-
9	Total Wholesale - Utility	20	31	55	61	60	60	61
	Contract (2)							
10	Rate M4	519	521	445	438	442	421	385
11	Rate M7	532	486	390	253	219	96	95
12	Rate 20 Storage	-	-	-	-	-	-	-
13	Rate 20 Transportation	340	379	433	416	471	471	483
14	Rate 100 Storage	-	-	-	-	-	-	-
15	Rate 100 Transportation	1,112	1,138	836	866	898	961	1,000
16	Rate T-1 Storage	-	-	-	-	-	-	-
17	Rate T-1 Transportation	3,024	3,194	2,648	3,009	3,402	4,308	4,100
18	Rate T-3 Storage	-	-	-	-	-	-	-
19	Rate T-3 Transportation	276	274	264	254	264	270	273
20	Rate M5	504	498	475	528	511	520	532
21	Rate 25	215	210	159	171	108	98	98
22	Rate 30	-	-	-	-	-	-	-
23	Total Contract	6,521	6,700	5,650	5,935	6,315	7,146	6,966
24	Total	11,927	12,058	10,922	11,182	11,739	12,402	12,032

Note:
(1) The impact of weather normalization for rates M1, M2, 01, and 10 is calculated based on the weather normalization methodology in place for each respective year.
(2) Union's contract and wholesale classes are not weather normalized.

UNION GAS LIMITED

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

Ref: T1 Rate Schedule

Certain T1 shippers may elect the Billing Contract Demand option, in which case firm deliveries that exceed the Billing Contract Demand quantity are charged the authorized transportation overrun rate.

a) What amount of authorized overrun revenue did Union receive from T1 customers electing the Billing Contract Demand option in 2010 and 2011?

b) What amount of authorized overrun revenue from T1 customers electing the Billing Contract Demand option is forecast for 2013?

c) Please describe how this authorized overrun revenue is reflected in 2013 rates.

Response:

a) The amount of authorized overrun revenue from Rate T1 customers electing the Billing Contract Demand option is:

   2010 - $287,106
   2011 - $606,335

b) Union is not forecasting any authorized overrun revenue.

c) N/A

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference: Exhibit C1, Tab 2

In Table 1 Union forecasts a declining Power related volumes 2013 Forecast compared to 2011 Actual, and 2012 Forecast. APPrO would like to better understand these declines, and the linkage, if any, between throughput and contract demand.

a) For each year from 2007 to 2013 and within each applicable rate class, please show the aggregate amount of gas-fired generating capacity (MW) identified by dispatchable and baseload (or self-dispatching (e.g. NUGs and CHP).

b) For each year from 2007 to 2013 and within each applicable rate class please show:

   i. The aggregate contract demand volumes for gas-fired generating capacity customers
   ii. The aggregate contracted minimum annual volumes

c) Please provide a list of the coal-fired generating plants in each of Union South and Union North franchise area and show the operative generating capacity (MW) at the beginning of each year from 2007 to 2013.

d) For 2013 please identify how much of Union's forecast of power related volumes in line 1, is attributable to the closure of coal units since 2007.

Response:

a)

MW capacity	2007	2008	2009	2010	2011	2012 (F)	2013 (F)
R100							
Baseload/Self	637	637	637	637	637	637	637
Dispatchable	0	0	0	0	0	0	0
R20							
Baseload/Self	110	110	110	110	110	110	110
Dispatchable	0	0	0	0	0	0	0
R25							
Baseload/Self	0	0	0	0	0	0	0
Dispatchable	2,130	2,130	2,130	2,130	2,130	2,130	2,130
T1							
Baseload/Self	185	185	185	185	185	185	185
Dispatchable	1,730	1,814	2,494	2,494	2,494	2,494	2,494

b)

i. Daily contracted demand (firm and interruptible) in 10^3m^3

10^3m^3	2007	2008	2009	2010	2011	2012 (F)	2013 (F)
R100	3,539	3,539	3,539	3,539	3,539	3,539	3,539
R20	715	715	715	715	715	715	715
R25	15,111	15,111	15,111	15,111	15,111	15,111	15,111
T1	8,643	9,944	13,424	13,424	13,424	13,424	13,424

ii. Firm and interruptible minimum annual volumes in 10^3m^3

10^3m^3	2007	2008	2009	2010	2011	2012 (F)	2013 (F)
R100	789,479	789,479	789,479	789,479	789,479	789,479	789,479
R20	0	0	0	0	0	0	0
R25	4,500	4,500	4,500	4,500	4,500	4,500	4,500
T1	1,240,997	1,240,997	1,256,837	1,256,837	1,256,837	1,256,837	1,256,837

c)

MW Capacity (1)	2007	2008	2009	2010	2011	2012 (F)	2013 (F)
Union North							
Thunder Bay	306	306	306	306	306	306	306
Union South							
Lambton	1,900	1,900	1,900	1,900	950	950	950
Nanticoke	3,760	3,760	3,760	3,760	2,820	1,880	1,880

Note: (1) Information taken from OPG website.

d) The specific volume attributable to the closure of the coal units since 2007 is 5,000 10^3m^3 forecast for the Thunder Bay coal conversion project.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference**:** Exhibit C1, Tab 2

In Table 2 Union forecasts a declining Total Revenues in 2013 Forecast compared to 2010 Actual, 2011 Actual, and 2012 Forecast. APPrO would like to better understand the rationale for the decline.

a) Please provide the major econometric or other material assumptions used to prepare this forecast that materially affect the revenue forecast.

b) Please provide Union's natural gas price elasticity's of demand for each of the sectors in Table 2.

c) Please provide revenue assumptions for 2013 associated with interruptible or other discretionary revenues for each market sector.

Response:

a) The major economic and other material assumptions that affect the revenue forecast are contained in Exhibit A2, Tab 1 schedule 1, page 16 to 24. Key econometric assumptions, foreign exchange rate and various energy prices, are contained in the 2013 REGN DATA file Apr 2012 Excel file in each market tab.

b) Union does not develop a price elasticity of demand for the contract market.

c) The general assumptions underpinning Union's revenue forecast can be found in the Application Summary at Exhibit A2, Tab1, Schedule 1, pp. 16 to 24.

   In the small to mid-size markets, consumption of interruptible volumes would be captured in the regression analysis variables that underpin the econometric forecast for the forecast period.

   In the large Contract market, where the bottom-up forecasting approach is used, Account Manager's review historic interruptible revenue consumption for each customer, and then apply interruptible trend usage to the forecast period.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit C1, Tab 1
Exhibit C1, Summary Schedules 1, 2, 3 and 4

With respect to the "Volume Comparison by Market Sector", for the period 2007 through to 2013 shown in Tables 1 and 2 of Exhibit C1, Tab 2 and the "Volume Comparison by Rate Class" shown in Table 3 of Exhibit C1, Tab 2, please provide the following additional information:

a) Add a column to each of Tables 1, 2 and 3 to show the number of customers in 2013 in each market sector and each rate class;

b) For each market sector and for 2013 only, please provide an estimate of the number of customers, the volume, and the revenue that is attributable to customers that Union would classify as manufacturers;

Response:

a) and b) Please see Attachment 1, Attachment 2 and Attachment 3. Customer numbers are as forecast at December 31, 2013.

Volume Comparison by Market Sector

2007 Board-Approved through 2013 Forecast

(10^6m^3)

	Market Sector	Board-approved 2007	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013	Forecast Volume Not MFG 2013	Forecast Volume MFG 2013	Forecast Customer # Not MFG 2013	Forecast Customer # MFG 2013
1	Power	1,831	2,078	1,659	1,854	2,349	2,464	2,215	2,189	2,189	0	28	0
2	Steel/Chemical/Refinery	3,374	3,272	3,523	2,971	3,271	3,582	3,866	3,734	0	3,734	0	34
3	LCI/Key	2,825	2,806	2,697	2,218	2,163	2,180	2,110	2,117	522	1,596	109	227
4	Greenhouse	146	173	203	197	246	287	303	315	315	0	101	0
5	Wholesale/REM	346	297	305	319	315	324	330	334	334	0	6	0
6	Totals (1)	8,521	8,625	8,386	7,560	8,344	8,837	8,824	8,689	3,359	5,329	244	261

(1) Excludes MAV Volumes

Revenue Comparison by Market Sector
2007 Board-Approved through 2013 Forecast
($ Millions)

Line No.	Market Sector	Board-approved 2007	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013	Forecast Revenue Not MFG 2013	Forecast Revenue MFG 2013	Forecast Customer # Not MFG 2013	Forecast Customer # MFG 2013
1	Power	23.5	26.8	26.3	29.0	32.2	32.7	29.7	29.5	29.5	0.0	28	0
2	Steel/Chemical/Refinery	37.2	38.5	37.7	37.0	36.7	38.4	36.1	35.5	0.0	35.5	0	34
3	LCI/Key	44.8	45.1	43.9	39.5	36.8	36.4	35.2	34.7	10.2	24.5	109	227
4	Greenhouse	4.0	3.9	5.2	4.9	5.8	6.3	6.2	6.5	6.5	0.0	101	0
5	Wholesale/REM	6.2	5.5	5.7	5.8	5.7	5.5	5.4	5.4	5.4	0.0	6	0
6	Totals [(1)]	115.7	119.8	118.8	116.2	117.2	119.2	112.6	111.6	51.6	59.9	244	261

(1) 2007 actual to 2013 Revenue is calculated using Q1, 2011 Rates.

Volume Comparison by Rate Class
2007 Board-Approved through 2013
Forecast
(10^6m^3)

Line No.	Rate Class	Board-approved 2007	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Forecast 2012	Forecast 2013	Forecast Volume Not MFG 2013	Forecast Volume MFG 2013	Forecast Customer # Not MFG 2013	Forecast Customer # MFG 2013
1	100	2,203	2,015	1,964	1,806	1,883	1,892	1,904	1,891	896	995	6	11
2	20	505	451	481	557	546	645	569	610	390	220	30	33
3	25	101	424	308	200	220	158	133	129	48	82	35	57
4	T1	4,232	3,831	3,757	3,446	4,102	4,607	4,814	4,666	81	300	17	47
5	M7	278	584	554	309	315	258	149	147	363	168	1	3
6	M4	452	520	519	446	439	442	409	380	1,196	3,471	38	77
7	M5	405	504	498	476	525	511	519	531	52	95	111	33
8	Other (T3,M9,M10)	346	296	305	319	315	324	330	334	334	0	6	0
9	Totals [(1)]	8,521	8,625	8,386	7,560	8,345	8,837	8,827	8,688	3,359	5,329	244	261

(1) Excludes MAV Volumes

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit C1, Tab 1
Exhibit C1, Summary Schedules 1, 2, 3 and 4

To help us evaluate Union's forecasts, please broaden the Throughput information provided in Exhibit C1, Summary Schedule 1 to show, for lines 10 to 23 inclusive, the Throughput estimates provided to Union by its contract customers for each of the years 2007 to 2013 inclusive, along with the following information:

a) The extent to which Union, in its budget in each year, modified the estimates provided by customers; and

b) The extent to which Actuals in each year differed from the estimates provided by Union's customers.

Response:

a) and b) Union's forecast methodology is described at Exhibit C1, Tab 2, pages 4 through 6.

Union does not require detailed consumption forecasts to be produced by the customer. Consequently, Union cannot produce the table as requested.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit C1, Tab 1
Exhibit C1, Summary Schedules 1, 2, 3 and 4

Please broaden Exhibit C1, Summary Schedules 3 and 4 to show the forecast revenues for 2012 and 2013 in a scenario where Union adopts, without any change, the Throughput estimates provided by its customers.

Response:

Please see the response at Exhibit J.C-3-14-2.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit C1, Tab 3, page 10

In the update on Short-term Transportation Revenue (C1/T3/Table 3), the revenues related to the St.Clair/Bluewater system has been revised from $1.2 million to $3.5 million in 2011 which translates to almost a three-fold increase.

a) Please provide reasons for the significant difference between the outlook and actual numbers in 2011.

b) Is it a one-time increase? If not, will the revenue generation carry over to 2012 and 2013?

Response:

a) In Union's original filed evidence, the 2011 Short-term Transportation Revenue Outlook did not include any revenue for the St. Clair Line; the total revenue of $1.2 million was entirely for the Bluewater system. This was based on the expectation that the St. Clair Line would remain a non-utility asset.

   In Union's updated evidence, 2011 Actual Short-term Transportation Revenue reflected the return of the St. Clair Line as a utility asset, per EB-2012-0048. The 2011 Actual Short-Term Transportation Revenue associated with St. Clair was $2.0 million.

b) Union does expect that revenue generation will carry over into 2012 and 2013 as the St. Clair Line is expected to remain a utility asset.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 3, Original & Updated

a) Please provide further details on the capacity forecast to be turned back in 2013 at lines 17-19 of page 6. In particular, please provide the details of the amounts to be turned back and the current status of this forecast turn back.

b) Please explain the drop from $3.5 million to $1.8 million in the St. Clair/Bluewater system short-term transportation revenue shown in Table 3 of the updated evidence.

c) Please explain the increase in exchange revenue shown in Table 4 for 2011 of $31.7 million versus the original forecast of $25.3 million. How many months of actual data were included in the original forecast for 2011?

d) Does Union have any more recent forecasts for the average price for short-term storage space in 2012 and 2013? If yes, please provide these forecasts and the information/assumptions used to generate these forecasts.

Response:

a) 2013 turnback is discussed at Exhibit C1, Tab 3, Original and Updated, page 6.

Dawn-Kirkwall Turnback:

The 2013 forecast includes turnback of 286,198 GJ/d for Dawn-Kirkwall. Since the forecast was completed, Union received notice of our customers' election to turn back 186,664 GJ/d, effective November 1, 2013. The remaining 99,534 GJ/d of Dawn-Kirkwall contracts have been extended to October 31, 2014.

Dawn-Parkway Turnback:

The forecast also includes turnback of 67,000 GJ/d for Dawn-Parkway. Since the forecast was completed, Union received notice of our customers' election to turn back 123,212 GJ/d. Of this, 121,212 GJ/d is effective November 1, 2013 and the balance is effective April 1, 2013.

b) The 2011 Short-Term Transportation Actual Revenue of $3.5 million for St.Clair/Bluewater system reflects the return of the St. Clair Line as a utility asset, per EB-2012-0048. In 2011, the St. Clair Line contributes $2.0 million to the Short-Term Transportation revenues.

The forecast of 2012 and 2013 Short-Term Transportation revenue assumed that the St. Clair Line would not be returned as a utility asset, and therefore does not include any St. Clair Line revenue.

c) The 2011 revenue outlook of $25.3 million included actual data to June and forecasted activity for the remainder of 2011. During the last six months of 2011, Union transacted a higher quantity of exchanges than forecast, and realized an increase in forecasted values.

d) Union has not updated the forecast for Short-Term Storage for 2013. However, the average short-term peak storage value of contracts executed in 2012 is $0.84 CDN/GJ.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit C1, Tab 3, Table 4

Please update the status of the TCPL FT-RAM Program.

Response:

The status of the TCPL FT-RAM program will be determined in TCPL's Restructuring and Tolls Proceeding which is now before the National Energy Board (RH-003-2011). Within its application, TCPL has proposed that the FT-RAM program be discontinued effective January, 2013.

Union, as part of the Market Area Shippers group has submitted evidence supporting its continuation.

UNION GAS LIMITED

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

Ref: Exhibit H1, Tab 1, page 13

In the H evidence it states that Union has included the ratepayer portion of the S&T transactional service revenue in the revenue stream for ratemaking purposes in 2013. That revenue is $17.840 million for in-franchise rates. Please reconcile that amount with the amounts provided at Exhibit C1/T3. Please provide a detailed explanation as to how that amount was derived. Please include all assumptions.

Response:

The S&T transactional revenue of $17.840 million represents the ratepayer portion of net revenue (forecast revenue less allocated costs) that was included in Union's November 23, 2011 Phase II filing.

In Union's updated Phase II evidence filed on March 27, 2012, Exhibit H1, Tab 1, page 10 states that "Union proposes to include S&T transactional services revenue of $20.852 million in in-franchise rates". The updated S&T transactional revenue represents the ratepayer portion of net revenue (forecast revenue less allocated costs) included in the in-franchise revenue stream for ratemaking purposes in 2013.

The tables provided in evidence at Exhibit C1, Tab 3, Updated include Union's storage and transportation ("S&T") revenue forecast for 2012 and 2013. To reconcile the 2013 S&T revenue, please refer to Exhibit H3, Tab 1, Schedule 2, pages 9 to 11, column (b).

For the reconciliation of the S&T revenue, please see the response at Exhibit J.H-1-2-6.

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

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit B1, Tab 9

Preamble: Union discusses the Parkway West construction project.

a) Please confirm that additional revenue earned through the sale of short term transportation service made possible by the Parkway West Project would be captured in the Short Term Transportation and Exchanges Revenue Forecast. If not, please explain where this revenue would be recorded.

b) Please list all of the potential services under which Union could sell this LCU capacity using the services described in Union's Priority of Service Policy.

c) Please explain how Short Term Transportation and Exchanges Revenue is shared between Union shareholders and Union ratepayers.

Response:

a) Please see the response at Exhibit J.B-1-7-11 a).

b) Please see the response at Exhibit J.B-1-7-11 a).

c) Short-term Transportation and Exchanges Revenue is part of Union's regulated revenue stream for ratemaking and is not subject to any specific sharing mechanism.

During the current IR framework, regulated earnings were subject to earnings sharing.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pg 8, lines 4-7

Preamble: Union discusses its revenue projection for the Ojibway to Dawn line.

a) Please provide the design day and peak day capacity of the Ojibway to Dawn line.

b) Please provide the average daily throughput and peak day throughput on the Ojibway to Dawn line for each of the last 10 years and the forecast for the next 15 years.

c) Please provide the annual load factor on the Ojibway to Dawn line for each of the last 10 years and the forecast for the next 15 years.

Response:

a) The design day capacity and the peak day capacity for the Ojibway to Dawn line is 208,528 GJ/d.

b) Please see Attachment 1 for average daily throughput for firm and interruptible nominated exfranchise activity for 2007-2011 and forecasted firm throughput for 2012-2013.

c) Please see the response at b) above.

Utilization - Ojibway to Dawn 2007-2013 (GJ)

	Actual					Forecast	
	2007	2008	2009	2010	2011	2012	2013
Bluewater to Dawn							
Average Daily Actual Throughput [1]	47,084	49,274	98,515	111,683	106,665	81,892	83,349
Highest Day Actual Throughput [1]	142,605	155,680	162,203	148,575	169,491		
Load Factor (Annual)	23%	24%	47%	54%	51%	39%	40%

Note:
(1) 2012 and 2013 only includes firm throughput.

UNION LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pg 7, Table 2
Union Website[1], C1 Transportation Services, Bluewater Interconnect listed as a service point

Preamble: Union lists the Bluewater Interconnect as an option for C1 Transportation Service that "lets you transport between upstream markets from Dawn".

a) Please provide the current design day and peak day capacity of the Bluewater river crossing.

b) Please provide the average daily throughput and peak day throughput on the Bluewater river crossing for each of the last 10 years and the forecast for the next 15 years.

c) Please provide the annual load factor on the Bluewater to Dawn path for each of the last 10 years and the forecast for the next 15 years.

d) Please provide the current design day and peak day capacity of the Bluewater to Dawn path.

e) Please provide the average daily throughput and peak day throughput on the Bluewater to Dawn path for each of the last 10 years and the forecast for the next 15 years.

f) Please provide the annual load factor on the Bluewater to Dawn path for each of the last 10 years and the forecast for the next 15 years.

g) Does the C1 Long-term Transportation outlook for 2011 and forecast for 2012 and 2013 contain any revenue for Bluewater to Dawn C1 Transportation Service? If not, why not?

h) Please confirm that Union affiliate St Clair Pipelines Management Inc. is proposing to replace the current leased NPS 12 line crossing the St Clair River with a St.Clair-owned NPS 20 line.

i) Please provide the design day and peak day capacity of the Bluewater river crossing after the new NPS 20 river crossing pipe is placed into service.

j) What firm contracts underpin the construction of the new NPS 20 Bluewater river crossing?

[1] http://www.uniongas.com/storagetransportation/services/transportation/c1transport.asp

k) Please provide the forecast annual load factor on the Bluewater river crossing for the next 15 years.

l) Please provide the annual costs that Union has incurred in relation to the existing Bluewater NPS 12 river crossing for the past 10 years ending 2011 and its forecast of the annual costs that Union will incur in the 10 years after the new NPS 20 river crossing is put into service.

m) Please provide the design day and peak day capacity of the Bluewater to Dawn path after the new NPS 20 river crossing pipe is placed into service.

n) Would the completion of the NPS 20 river crossing project impact Union's forecast of C1 Long-term Transportation revenue? If not, why not?

o) What is the rationale for replacing the line when the lease on the current river crossing expires?

p) Please provide the cost-benefit analysis that Union and/or St. Clair performed to support the replacement of the leased river crossing line on the expiry of the lease.

Response:

a) The Bluewater river crossing is an NEB regulated facility which Union does not own and is not relevant to this proceeding. Union is unable to provide the information requested.

b) Please see the response at c) below. Union does not own the Bluewater river crossing and therefore is unable to provide the information requested.

c) Please see Attachment 1 for the load factor, average daily throughput and peak day throughput for firm and interruptible nominated ex-franchise activity for 2007-2011 and forecasted firm throughput for 2012-2013 for the Bluewater-Dawn path.

d) Bluewater to Dawn path design day and peak day capacity is 213,875 GJ/d.

e) Please see the response at c) above.

f) Please see the response at c) above.

g) The 2011 Actual and the 2012 and 2013 Forecasts do not include any C1 long-term transportation revenue. All revenue earned in 2011 was from short-term firm or interruptible transportation services and was reflected in the Short-term Transportation Revenue (see Exhibit C1, Tab 3, Table 3). The 2012 and 2013 Forecasts include forecast revenues from

Bluewater to Dawn transportation in the Short-Term Transportation Revenue, since at the time of completion of the forecasts; there were no long term contracts.

h) Confirmed. St. Clair Pipelines is replacing the section of pipe between the International Border and the Bluewater Valve Site.

i) The requested information is available in St. Clair Pipeline Management's Bluewater River Crossing Replacement Section 58 Application with the National Energy Board found at the following NEB site:

https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=792060&objAction=browse&sort= name

j) Please see the response to a).

k) Please see the response to a)

l) Union has incurred an annual cost of $629,625 related to transportation services contracted with St. Clair Pipelines for the years 2007 through 2011. The cost is not anticipated to change until 2013 when the cost is anticipated to increase to approximately $650,000.

m) Please see the response to d).

n) If the additional demands from a C1 Long-term contract attributable to this path were incorporated into Union's 2013 forecast, the impact would be a reduction in C1 Short-term Firm Transportation and an off-setting increase in the C1 Long-term Firm Transportation portion of the forecast.

o) Please see the response to i).

p) Union has not performed a cost benefit analysis to support the replacement of the leased river crossing. Union expects that the annual revenue generated on the Bluewater-Dawn path will more than offset the cost of the transportation contracted with St. Clair Pipelines.

Utilization - Bluewater to Dawn 2007-2013 (GJ)

	Actual					Forecast	
	2007	2008	2009	2010	2011	2012	2013
Bluewater to Dawn							
Average Daily Actual Throughput (1)	27,999	20,528	31,946	42,677	95,302	102,193	101,786
Highest Day Actual Throughput (1)	182,439	174,509	190,046	209,080	224,833		
Load Factor (Annual)	13%	10%	15%	20%	45%	48%	48%

Note:

(1) 2012 and 2013 only includes firm throughput.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pg 3

Preamble: Union discusses the resale of Dawn-Kirkwall and Dawn-Parkway capacity of 211,407 GJ/d in 2011 & 122,950 GJ/d in 2012.

a) For each of the contracts that constituted the resale described in the referenced evidence, please provide the following information:

   i) starting dates
   ii) ending dates
   iii) receipt and delivery points
   iv) contract type (M12, C1, M12-X, etc.)

Response:

Please see Attachment 1.

Line		Customer	Path	Start Date	End Date	Contract Type	
1	2011	A	Dawn-Kirkwall	01-Nov-11	31-Oct-16	M12	
2		B	Dawn-Parkway	01-Nov-11	31-Oct-16	M12	
3		C	Dawn-Parkway	01-Nov-11	31-Oct-16	M12	
4		D	Dawn-Parkway	01-Nov-11	31-Oct-16	M12	
5		E	Dawn-Parkway	01-Nov-11	31-Oct-16	M12	
6		F	Dawn-Parkway	01-Nov-11	31-Oct-21	M12	
7		G	Dawn-Parkway	01-Nov-11	31-Oct-16	M12	
8		H	Dawn-Parkway	01-Nov-11	31-Oct-16	M12	
9		I	Dawn-Parkway	01-Nov-11	31-Oct-16	M12	
10	2012	J	Dawn-Parkway	01-Apr-12	01-Oct-22	M12	(1)
11		K	Dawn-Parkway	01-Nov-12	31-Oct-32	M12	

Notes:

(1) This contract was completed after Union's evidence was filed. In the evidence,Union forecasted this contract to be effective May 1, 2012.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pgs 3-4

Preamble: On page 3; Union discusses the resale of Dawn-Parkway capacity of 122,950 GJ/d starting in 2012. On page 4; Union discusses incremental new sales of Dawn-Parkway capacity of 133,950 GJ/d which commence in May and November 2012 and a Kirkwall-Parkway contract of 88,497 GJ/d commencing November 1, 2012.

a) Please explain the difference between the volumes discussed on page 3 and the volumes discussed on page 4.

b) For each of the contracts that constituted the resale described in the referenced evidence, please provide the following information:

   i) starting dates;

   ii) ending dates;

   iii) receipt and delivery points;

   iv) contract type (M12, C1, M12-X, etc.)

   v) the facilities that were added by Union to provide the service associated with each of the contracts and the capital cost of those facilities ;

   vi) whether the contract terms described in the responses to (i) and (ii) above were requested by the shippers or required by Union; and

   vii) if the contract terms were required by Union, please provide the rationale for these requirements.

Response:

a) The quantity of 133,950 GJ/d described at Exhibit C1, Tab 3, page 4, line 17 is the total forecasted new sales of 2012 Dawn-Parkway capacity. The quantity of 122,950 GJ/d described at Exhibit C1, Tab 3, page 3, line 10 are sales of 2011 turnback which commence in 2012. This quantity of 122,950 GJ/d is a subset of the total 2012 sales.

b) i) – iv) Please see Attachment 1.

v) There were no facilities added by Union to provide service for the new 2012 contracts. This service was provided using capacity available from turnback capacity.

vi) – vii) The capacity for contracts on lines 1 and 2 of Attachment 1 were awarded based on terms outlined in an open season. The terms for the contract identified on line 3 were mutually agreed upon between Union and customers.

Line No.		Customer	Path	Start Date	End Date	Contract Type	
1	2012	A	Dawn-Parkway	01-Apr-12	01-Oct-22	M12	(1) (2)
2		B	Dawn-Parkway	01-Nov-12	31-Oct-32	M12	(1)
3		C	Dawn-Parkway	01-Apr-12	31-Mar-15	C1	(2)

Notes:

(1) These are the same contracts as outlined at Exhibit J.C-4-7-4 Attachment 1.

(2) These contracts were completed after Union's evidence was filed. In the evidence, Union forecasted these contracts to be effective May 1st, 2012.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pg 5

Preamble: Union discusses a sale of Kirkwall-Parkway capacity of 174,752 GJ/d commencing November 1, 2013.

a) For the above mentioned contract please provide the following information:
   i) starting dates;
   ii) ending dates;
   iii) receipt and delivery points;
   iv) contract type (M12, C1, M12-X, etc.)
   v) the facilities that were added by Union to provide the service associated with each of the contracts and the capital cost of those facilities ;
   vi) whether the contract terms described in the responses to (i) and (ii) above were requested by the shippers or required by Union; and
   vii) if the contract terms were required by Union, please provide the rationale for these requirements.

Response:

a)

i)-iv) Please see Attachment 1.

v) There were no facilities added by Union to provide this service. This service was provided using capacity available from turnback capacity.

vi-vii) This capacity was awarded and contracted based on terms outlined in an open season.

	Customer	**Path**	**Start Date**	**End Date**	**Contract Type**
2013	A	Kirkwall-Parkway	01-Nov-13	31-Oct-23	M12

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Union Gas Limited Open Season announcement dated February 22, 2012 for service on Union's St. Clair (MICHCON) to Dawn transportation path.

Preamble: The referenced announcement describes an open season for 180,000 MMBtu/d of firm capacity from St. Clair (MICHCON) to Dawn commencing as early as April 1, 2012. The open season closed on March 9, 2012 with contracts expected to be executed no later than March 31, 2012.

a) Please specify the quantity and term for each contract awarded as a result of this open season.

b) Please describe the impact of the contracts described in (a) on the storage and transportation forecast for 2013.

c) Please describe the impact of the contracts described in (a) on rates for 2013.

Response:

a) Union awarded one contract for 21,101 GJ/d, with a one-year term starting April 1, 2012.

b) The open season capacity and associated revenue for the St. Clair (MICHCON) to Dawn transportation path was included in the 2013 Forecast as C1 Short-term Transportation.

c) If the additional demands of 21,101 GJ/d resulting from the recent St. Clair to Dawn open season were incorporated in Union's 2013 forecast, there would be a shift in Ojibway/St. Clair demand costs of approximately $272,000 from South in-franchise rate classes to the C1 rate class.

   The impact on Union's 2013 proposed rates would be minimal.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Union Gas Limited Open Season announcement February 24, 2012 for service on Union's Bluewater (interconnect with Bluewater Gas Storage) to Dawn transportation path.

Preamble: The referenced announcement describes an open season for 140,000 GJ/d of firm capacity from Bluewater to Dawn commencing November 1, 2012. The open season closed on March 12, 2012 with contracts expected to be executed no later than March 31, 2012.

a) Please indicate the capacity available on the Bluewater to Dawn path as of April 1, 2012 and why the commencement date of November 1, 2012 was stipulated in the open season announcement.

b) Please specify the quantity and term for each contract awarded as a result of this open season.

c) Please describe the impact of the contracts described in (a) on the storage and transportation forecast for 2013.

d) Please describe the impact of the contracts described in (a) on rates for 2013.

Response:

a) Capacity available on Bluewater to Dawn path as of April 1, 2012 was 20,000 GJ/day. The open season outlined a start date of November 1, 2013, which is the first transportation season after the new contracts with St. Clair Pipelines have been executed.

b) Union received one bid in this open season and is currently in negotiation with the customer to finalize the agreements.

c) The available capacity was forecast as C1 Short-term Transportation. Therefore the impact on the 2013 forecast would be a reduction in C1 Short-term Transportation revenue and an equal and offsetting increase in C1 Long-term Transportation revenue.

d) If the additional demands of 20,000 GJ/d resulting from the recent Bluewater to Dawn open season were incorporated in Union's 2013 forecast, there would be a shift in Ojibway/St. Clair demand costs of approximately $258,000 from South in-franchise rate classes to the C1 rate class.

The impact on Union's 2013 proposed rates would be minimal.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pg 12, lines 5-6 "The single biggest factor contributing to growth in exchange revenue was the utilization of the TCPL FT RAM program starting 2008."
Exhibit C1, Tab 3, pg 11, lines 13-14 "The 2012 forecast assumes the TCPL FT RAM program will be eliminated on November 1, 2012. A full year impact of FT RAM program being discontinued is reflected in 2013."
Exhibit D1, Tab 1, pg 3, line 2

Preamble: TransCanada has applied to the National Energy Board to eliminate the RAM feature of TransCanada's FT service and Union and others have filed evidence in support of retaining RAM. Due to the uncertainty thus surrounding FT RAM, and the impact of potential FT RAM revenues on the Short-Term Transportation and Exchanges Revenue Forecast, TransCanada seeks to better understand the historical and forecast amount of revenue attributable to FT RAM and how the uncertain future of FT RAM will be managed by Union with respect to the 2013 rates.

a) Please provide the following historical information, for November 2007 to March 2012, by month:

   i) Total revenue attributable to FT RAM, in dollars.

   ii) Average revenue attributable to FT RAM, in $/GJ.

b) Please provide the following forecast information, for the months of April 2012 through to December 2012, by month:

   i) Total revenue attributable to FT RAM, in dollars.

   ii) Average revenue attributable to FT RAM, in $/GJ.

c) In the event FT RAM is not discontinued as of November 1, 2012, please describe how Union will alter the Short-Term Transportation and Exchange Revenue forecast for 2012-2013 for the purposes of establishing rates.

d) Please provide the amount of FT RAM credits, in dollars, that Union has generated by month since November 2007.

e) Please provide a monthly breakdown of the Exchange Revenue shown in Exhibit C1, Tab 3 Table 4 into the following categories:

   i) Use of Union's upstream transportation capacity to provide exchange services to third parties.

   ii) Net revenue generated from capacity releases

   iii) Revenue obtained as a result of TCPL's FT RAM program.

   iv) Other

   v) Total exchange revenue.

f) Please explain how the 2013 Exchange Revenue forecast is treated in determining Union's revenue requirement.

g) Please explain how any variance between actual and forecast 2013 Exchange Revenue is allocated between Union shareholders and Union ratepayers.

Response:

a) Please see Attachment 1, lines 1 and 2.

b) Please see Attachment 1, lines 1 and 2.

c) For 2012, Union forecasted revenue of $14.2 million attributable to RAM, assuming the RAM program was eliminated November 1, 2012. If TCPL's RAM program is not eliminated on November 1, 2012, Union's 2012 forecast of exchange revenue attributable to RAM would increase by $3.6 million to $17.8 million. For 2012, exchange revenues, including those associated with RAM, are subject to Union's EB-2007-0606 earnings sharing mechanism.

   If TCPL's RAM program is not eliminated on November 1, 2012, Union's 2013 revenue forecast attributable to RAM would be $11.6 million. The forecast of $11.6 million assumes the structure and parameters of TCPL's RAM program does not change materially, and is based on actual 2011 activity. The 2013 revenue decreases compared to the 2012 forecast are due to expected TCPL toll reductions, price anomaly corrections, and turnback of some of Union's capacity on TCPL.

   For 2013, there are two primary options to manage the possibility of TCPL's RAM program continuing beyond 2012:

1. Increase the S&T forecast to include revenue of $11.6 million and create a deferral account to manage the difference between the forecast revenue and the actual revenue attributable to RAM; or,

2. Maintain the current S&T forecast and create a deferral account to manage the difference between the forecast revenue and the actual revenue attributable to RAM.

d) Please see Attachment 1 Table 1, line 3.

e)
   i. Please see Attachment 2 Table 2, line 1.
   ii. Please see Attachment 2 Table 2, line 2.
   iii. Please see Attachment 2 Table 2, line 3.
   iv. Please see Attachment 2 Table 2, line 4.
   v. Please see Attachment 2 Table 2, line 6.

f) The exchange revenue forecast of $9.1 million for 2013 is included as a reduction to delivery rates. Please see Union's S&T transactional margin included in the 2013 in-franchise rates at Exhibit H3, Tab 10, Schedule 1, Updated.

g) Union will retain the variance, positive or negative, between the 2013 forecast and actual exchange revenues, subject to the earnings sharing mechanism associated with Union's incentive regulation framework.

Impact of RAM Program *
$ Millions **

Line No.			2007		2008		2009		2010		2011		2012 Forecast
1	Net Revenue Attributable to RAM Benefit ***	$	0.4	$	5.0	$	14.0	$	11.7	$	22.0	$	14.2
2	Net Revenue ($/GJ)****	$	0.01	$	0.03	$	0.09	$	0.08	$	0.16	$	0.11
3	RAM credits generated	$	1.1	$	16.7	$	14.5	$	31.8	$	32.2		n/a

* Includes STS and FT RAM
** Unless otherwise noted
*** Union's approximation of exchange revenue related to the RAM program. This is a subset of Net Exchange Revenue.
**** Net Revenue ($/GJ) calculated using Union's contracted quantities eligible for STS and FT RAM.

Components of Net Exchange Revenue
$Millions

Line No.		2007	2008	2009	2010	2011	2012 Forecast	2013 Forecast
1	Base exchanges	$ 3.0	$ 6.6	$ 6.5	$ 8.0	$ 9.7	$ 6.9	$ 9.1
	RAM Revenue:							
2	Capacity Assignments	0.4	3.1	10.2	10.7	14.4	1.4	-
3	RAM Optimization *	-	0.0	2.8	4.7	9.6	13.7	-
4	Other	-	1.9	1.0	(3.7)	(2.0)	(0.9)	-
5	Subtotal **	$ 0.4	$ 5.0	$ 14.0	$ 11.7	$ 22.0	$ 14.2	-
6	Total Net Exchange Revenue	$ 3.40	$ 11.60	$ 20.50	$ 19.70	$ 31.70	$ 21.1	$ 9.1

* Union's approximation of exchange revenue related to the RAM program. Includes
** Net revenue attributable to RAM benefits.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pg 12, lines 5-6 "The single biggest factor contributing to growth in exchange revenue was the utilization of the TCPL FT RAM program starting 2008."
Exhibit C1, Tab 3, pg 11, lines 17-19 "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."

Preamble: TransCanada requires more information about Union's Exchange Revenues to be able to determine if the 2013 Short Term Transportation and Exchanges Revenue Forecast is appropriate.

a) Please provide a detailed description of how Union obtains revenue as a result of FT RAM.

b) Please provide sample agreements of each type of transaction that results in the FT RAM revenue as described in reference 1 and 2.

c) Please provide, by month since 2008, quantities of FT capacity that Union has assigned to other counterparties that generated Exchange revenue or otherwise reduced Union's transportation costs. For each assignment, please provide the quantity, assignee, toll, and path of the transport assigned.

d) Please explain how Union exchanges gas between points on the Union system and points on the TransCanada system.

e) Please explain what transportation service is used to affect the exchange and how Union determines what to charge for the service.

f) Are exchanges done on a firm basis or an interruptible basis.

Response:

a) Union recognizes the benefit of the RAM Program in three general ways.

First, when balancing supply for its system customers, Union periodically has excess TCPL capacity that Union releases in the market. Union sees higher value for that capacity due to the RAM feature. All proceeds from that released capacity, including those higher proceeds earned as a result of the RAM Program, are returned directly to system customers to offset Unabsorbed Demand Charges (UDC).

Second, prior to November, 2007, Union used the RAM program primarily to fund a base minimal level of Interruptible Transportation (IT) to manage LBA fees in its northern delivery areas. Union expects this base level of IT to continue, regardless of the RAM program.

Third, starting in 2007, Union realized benefits of the RAM Program when optimizing its transportation portfolio. Union began to assign various long-haul firm transportation assets on a monthly, seasonal and annual basis in order to realize some of the value the market placed on TCPL pipe as a result of the RAM program. Since Union continued to purchase supply at Empress, alternative arrangements were required to deliver these supplies to Union's market once the capacity was assigned.

In 2008, Union began to use the RAM program by applying available RAM credits earned on empty FT pipe to transport Empress supplies to various delivery areas to meet market demands for customers. The flexibility to apply RAM credits to any path allowed Union to deliver supply to franchise customers across multiple delivery areas, such as the MDA, WDA, NDA, SSMDA, NCDA, CDA, EDA and SWDA. In addition, these credits could be used alone, or in combination with, other assets to serve exchanges to customers outside Union's franchise area. The credits earned via the RAM program are one of the resources Union employed to serve our customers.

b) Union's standard exchange agreements are included as Attachments 3 and 4 and can be found on Union's website at: http://www.uniongas.com/storagetransportation/resources/pdf/standardcontracts/Confirmation_Exchange.pdf for interruptible agreements and http://www.uniongas.com/storagetransportation/resources/pdf/standardcontracts/EnhancedExchangeAgreement.pdf for firm agreements.

c) Please see Attachment 1 and 2. Attachment 1 reports capacity assignments by month and by zone from November, 2007 which are related to RAM. It does not include any capacity assignments to Union's franchise customers. Attachment 2 shows TCPL tolls also by month and by zone from November 2007.

Union has not identified assignees as that information is commercially sensitive.

d) Union exchanges gas between Dawn and points east or west of Parkway by utilizing TCPL's interruptible transportation services as well other TCPL services such as diversions of firm contracts.

e) Interruptible services provided by TCPL are used to effect the exchange. When negotiating with customers for exchange services, Union includes in its considerations the basis differentials between points of receipt and delivery and the costs of providing the service.

f) Exchanges are done on both a firm and interruptible basis.

Capacity Assignments*

GJ/d

Line No.	Receipt Point	Delivery Area	Winter 07/08					Summer '08						
			Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	June '08	Jul '08	Aug '08	Sept '08	Oct '08
1	Empress	Eastern Zone	-	35,000	35,000	35,000	35,000	65,753	80,753	60,753	60,753	60,753	65,753	65,753
2	Empress	Northern Zone	-	-	-	-	-	5,000	5,000	5,000	5,000	5,000	5,000	5,000
3	Empress	Western Zone	-	-	-	-	-	-	-	-	12,000	12,000	8,000	5,000

Line No.	Receipt Point	Delivery Area	Winter 08/09					Summer '09						
			Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	June '09	Jul '09	Aug '09	Sept '09	Oct '09
4	Empress	Eastern Zone	28,000	48,000	48,000	48,000	48,000	77,556	97,556	97,556	108,556	108,556	108,556	97,556
5	Empress	Northern Zone	8,000	8,000	8,000	8,000	8,000	-	-	-	-	40,000	-	30,000
6	Empress	Western Zone	-	-	-	-	-	-	-	-	-	-	-	20,000

Line No.	Receipt Point	Delivery Area	Winter 09/10					Summer '10						
			Nov '09	Dec '09	Jan '10	Feb '10	Mar '10	Apr '10	May '10	June '10	Jul '10	Aug '10	Sept '10	Oct '10
7	Empress	Eastern Zone	80,000	80,000	80,000	80,000	80,000	92,832	92,832	92,832	92,832	92,832	92,832	92,832
8	Empress	Northern Zone	20,062	20,062	-	-	-	-	30,000	40,000	40,000	40,000	40,000	20,000
9	Empress	Western Zone	-	-	-	-	-	-	-	-	-	-	-	-

Line No.	Receipt Point	Delivery Area	Winter 10/11					Summer 11						
			Nov '10	Dec '10	Jan '11	Feb '11	Mar '11	Apr '11	May '11	June '11	July '11	Aug '11	Sept '11	Oct '11
10	Empress	Eastern Zone	60,000	60,000	60,000	60,000	60,000	60,000	96,796	110,000	110,000	110,000	110,000	110,000
11	Empress	Northern Zone	-	-	-	-	-	40,000	40,000	49,000	49,000	49,000	49,000	49,000
12	Empress	Western Zone	-	-	-	-	-	-	-	-	-	-	-	-

Line No.	Receipt Point	Delivery Area	Winter 11/12					Summer 12	
			Nov '11	Dec '11	Jan '12	Feb '12	Mar '12	Apr '12	May '12
13	Empress	Eastern Zone	74,796	60,000	60,000	60,000	80,000	117,796	117,796
14	Empress	Northern Zone	-	-	-	-	-	40,000	48,500
15	Empress	Western Zone	-	-	-	-	-	-	-

* not including capacity assignments to Union's franchise customers

Filed: 2012-05-04
EB-2011-0210
J.C-4-7-10
Attachment 2

100% Load Factor Posted Tolls

$C/GJ

Line No.	Receipt Point	Delivery Area	Winter 07/08					Summer '08						
			Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	June '08	Jul '08	Aug '08	Sept '08	Oct '08
1	Empress	Eastern Zone	1.03032	1.03032	1.09000	1.09000	1.09000	1.31000	1.31000	1.39999	1.39999	1.39999	1.39999	1.39999
2	Empress	Northern Zone	0.79389	0.79389	0.83269	0.83269	0.83269	1.02310	1.02310	1.09338	1.09338	1.09338	1.09338	1.09338
3	Empress	Western Zone	0.51804	0.51804	0.55056	0.55056	0.55056	0.67581	0.67581	0.72208	0.72208	0.72208	0.72208	0.72208

Line No.	Receipt Point	Delivery Area	Winter 08/09					Summer '09						
			Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	June '09	Jul '09	Aug '09	Sept '09	Oct '09
4	Empress	Eastern Zone	1.39999	1.39999	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000	1.19000
5	Empress	Northern Zone	1.09338	1.09338	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313	0.91313
6	Empress	Western Zone	0.72208	0.72208	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425	0.59425

Line No.	Receipt Point	Delivery Area	Winter 09/10					Summer '10						
			Nov '09	Dec '09	Jan '10	Feb '10	Mar '10	Apr '10	May '10	June '10	Jul '10	Aug '10	Sept '10	Oct '10
7	Empress	Eastern Zone	1.19000	1.19000	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808	1.63808
8	Empress	Northern Zone	0.91313	0.91313	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894	1.25894
9	Empress	Western Zone	0.59425	0.59425	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513	0.81513

Line No.	Receipt Point	Delivery Area	Winter 10/11					Summer 11						
			Nov '10	Dec '10	Jan '11	Feb '11	Mar '11	Apr '11	May '11	June '11	July '11	Aug '11	Sept '11	Oct '11
10	Empress	Eastern Zone	1.63808	1.63808	1.63808	1.63808	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290
11	Empress	Northern Zone	1.25894	1.25894	1.25894	1.25894	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219
12	Empress	Western Zone	0.81513	0.81513	0.81513	0.81513	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287

Line No.	Receipt Point	Delivery Area	Winter 11/12					Summer 12	
			Nov '11	Dec '11	Jan '12	Feb '12	Mar '12	Apr '12	May '12
13	Empress	Eastern Zone	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290	2.24290
14	Empress	Northern Zone	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219	1.74219
15	Empress	Western Zone	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287	1.13287

[Union Gas Logo]

[HUB___B_____]
[SA_____]
[Agreement Date]

Confirmation

Exchange

Attention: [Shipper Rep]

This Exchange Confirmation ("**Confirmation**") incorporates all of the terms and conditions of the Interruptible Service Hub Contract ([HUB___]) between Union Gas Limited ("**Union**") and [Shipper Name] ("**Shipper**") dated [Latest Amendment Date] (the "**Contract**"). All terms and conditions contained in the Contract, and any Schedules referenced by the Contract as amended from time to time, shall apply to this Confirmation, unless specifically set forth herein. In the event of any conflict or inconsistency between the terms and conditions of this Confirmation and those of the Contract, the terms and conditions of this Confirmation shall prevail.

Confirmation terms and conditions:

Service Type: Interruptible	
Term Start: [start date]	**Term End:** [end date]
Receipt Point (to Union): [receipt point]	**Delivery Point (to Shipper):** [delivery point]
Minimum Quantity: [Quantity] GJ/day ([converted] MMBtu/day)	**Maximum Quantity:** [Quantity] GJ/day ([converted] MMBtu/day)
Fuel: [fuel %] – up to [Quantity] GJ/day ([converted]mmbtu/day) at [location]	
Nominations: Must be received [hours] before the [window] nomination window	
Rate: Shipper agrees to pay Union $[Commodity Rate] [Currency]/[UOM] ([Converted Rate] [Currency] /[Converted UOM] which will be invoiced as utilized.	

If on any day Shipper fails to deliver the Authorized Quantity to any of the above noted Receipt Point(s), Shipper agrees to pay $0.1500000/GJ ($0.1582584/MMBtu) multiplied by the difference between the Authorized Quantity and the actual quantity delivered at the Receipt Point ("**Delivery Shortfall**") for every day that the Delivery Shortfall, or any portion thereof, remains, plus any verifiable costs incurred by Union that are directly attributable to Shipper's failure to deliver the Delivery Shortfall. Union retains the right to replace the Delivery Shortfall at any time throughout the period that the Delivery Shortfall, or any portion thereof, remains and Shipper shall use due diligence to deliver the Delivery Shortfall to Union promptly at the Receipt Point or Dawn (Facilities), as decided at Union's discretion. Should Union choose to replace the Delivery Shortfall, Shipper agrees to pay Union's costs to replace such gas at the Receipt Point or Dawn (Facilities), as decided at Union's discretion, plus an additional 25% of such costs.

If on any day, Shipper fails to accept the Authorized Quantity at any of the above noted Delivery Point(s) Shipper agrees to pay $0.1500000/GJ ($0.1582584/MMBtu) multiplied by the difference between the Authorized Quantity and the actual quantity accepted ("**Receipt Shortfall**") for every day that the Receipt Shortfall, or any portion thereof, remains, plus any verifiable costs incurred by Union that are directly attributable to the Shipper's failure to accept the Receipt Shortfall.

Shipper and Union agree that each party shall use reasonable efforts in order to balance as nearly as possible the quantity exchanged on a daily basis and to resolve any imbalances in a timely manner.

[Union Gas Logo]

All quantities will be converted to GJ for billing purposes. Conversion: 1 MMBtu = 1.055056 GJ.

This Confirmation may be signed and sent by facsimile or other electronic communication and this procedure shall be as effective as signing and delivering an original copy.

Please acknowledge your agreement to all of the above terms and conditions by signing and sending this Confirmation to Union Gas Limited at fax: (519) 358-4064 or email to both:
[email address of S&T Account Manager] and Storage.Transportation@uniongas.com.

Failure to provide a signed copy of this Confirmation to Union, or failure to object in writing to any specified terms in this Confirmation, within two business days of receipt of this Confirmation will be deemed acceptance of the terms hereof.

[Electronic Signature]	______________________________
[S&T Account Manager]	[Shipper Name] *Authorized Signatory*

[Union Gas Logo]

[HUB___E___]
[SA_____]
[Month day, year]

(Note: This document shell is for obligated firm Agreements; interruptible and other less firm Agreements are also available; please contact your Account Manager.)

Attention: [Shipper Rep]

Enhanced Exchange Service Agreement

This Enhanced Exchange Service Agreement (“**Agreement**”) incorporates all of the terms and conditions of the Interruptible Service Hub Contract ([HUB___]) between Union Gas Limited (“**Union**”) and [Shipper Name] (“**Shipper**”) dated [Latest Amendment Date] (the “**Contract**”). All terms and conditions contained in the Contract, and any Schedules referenced by the Contract, as amended from time to time, shall apply to this Agreement, unless specifically set forth herein. In the event of any conflict or inconsistency between the terms and conditions of this Agreement and those of the Contract, the terms and conditions of this Agreement shall prevail.

Agreement terms and conditions:

Service Type: [Firm]	
Term Start: [start date]	**Term End:** [end date]
Receipt Point (to Union): [receipt point]	**Delivery Point (to Shipper):** [delivery point]
Firm Exchange Quantity: [Quantity] GJ/day ([converted] MMBtu/day)	
Minimum Quantity: [Quantity] GJ/day ([converted] MMBtu/day)	**Maximum Quantity:** [Quantity] GJ/day ([converted] MMBtu/day)
Fuel: [fuel %] - [Quantity] GJ/day ([converted]mmbtu/day) at [location]	
Nominations: Must be received [hours] before the [window] nomination window.	
Rate: Shipper agrees to pay Union, a demand charge of $[Demand Charge] [Currency] which shall be invoiced in [#] equal monthly instalment(s).	

Shipper is obligated to deliver the Firm Exchange Quantity to the above noted Receipt Point(s), each and every day. If on any day Shipper fails to deliver the Firm Exchange Quantity to any of the above noted Receipt Point(s), Shipper agrees to pay $3.0000000/GJ ($3.1651680/MMBtu) multiplied by the quantity of gas not delivered to Union (“**Delivery Shortfall**”). In addition, should Union choose to replace such Delivery Shortfall, Shipper agrees to pay Union’s costs to replace such gas at the Receipt Point or Dawn, as decided at Union’s discretion, plus an additional 25% of such costs. If Union chooses not to replace such gas, Shipper agrees to pay $0.1500000/GJ ($0.1582584/MMBtu) for every day that the Delivery Shortfall, or any portion thereof, exists. Union retains the right to replace the Delivery Shortfall at any time throughout the period that the Delivery Shortfall, or any portion thereof, remains and Shipper shall use due diligence to deliver the Delivery Shortfall to Union promptly at Receipt Point or Dawn, as decided at Union’s discretion.

Shipper is obligated to accept the Firm Exchange Quantity at the above noted Delivery Point(s) each and every day. If on any day, Shipper fails to accept the Firm Exchange Quantity at any of the above noted Delivery Point(s), Shipper agrees to pay $3.0000000/GJ ($3.1651680/MMBtu) multiplied by the quantity of gas not accepted (“**Receipt Shortfall**”), plus the verifiable costs

[Union Gas Logo]

incurred by Union that are directly attributable to the Shipper's failure to accept the Receipt Shortfall.

Shipper and Union agree that each party shall use reasonable efforts in order to balance as nearly as possible on a daily basis and to resolve any imbalances in a timely manner.

All quantities will be converted to GJ for billing purposes. Conversion: 1 MMBtu = 1.055056 GJ.

This Agreement may be signed and sent by facsimile or other electronic communication and this procedure shall be as effective as signing and delivering an original copy.

Please acknowledge your agreement to all of the above terms and conditions by signing and sending this Agreement to Union Gas Limited at fax: (519) 358-4064 or email Storage.Transportation@uniongas.com with a copy to [email address of S&T Account Manager] or mail to **Union Gas Limited, 50 Keil Drive North, P.O. Box 2001, Chatham, ON, N7M 5M1, Attention: S&T Contracting.**

[Union Representative] (519) 436-____
Account Manager, Union Gas Limited

Acknowledged and Accepted
this ______ day of [Month, year]

[SHIPPER]
Authorized Signatory

____

UNION GAS LIMITED
Authorized Signatory

____

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, pg 2, Table 1
Exhibit C1, Tab 3, Schedule 1, line 5
Exhibit C1, Tab 3, Schedule 2, line 5

Preamble: In the summer of 2010 TransCanada contracted with Union to convert certain contracts to M12-X service effective September 1, 2011. The tables do not show any M12-X transportation revenue for the 2011 outlook.

Please provide an explanation as to why there is no M12-X revenue in the 2011 outlook and if appropriate amend the tables, and any related data in the Application, to reflect the 2011 revenue from TransCanada's M12-X contract.

Response:

In Union's original filed evidence (November 11, 2011), the impact of customer conversions to M12-X transportation contracts were included in the 2012 and 2013 only. Union's updated evidence (March 27, 2012) includes revenue associated with M12-X commencing in 2011.

UNION GAS LIMITED

Answer to Interrogatory from
TransCanada PipeLines Limited ("TCPL")

Reference: Exhibit C1, Tab 3, Schedule 1 and Schedule 3

Preamble: Impact of M12 Turnback and demands as of November 1, 2011, November 1, 2012 and November 1, 2013. Union Gas received turn back of Dawn to Kirkwall capacity and resold the capacity as M12 Dawn to Parkway, and Kirkwall to Parkway service.

a) What contract term does Union require for the sale of existing capacity? Please provide the rationale for requiring this term.

b) Please discuss Union's historical and current position with respect to the requirement that TransCanada offer one year term FT contracts, with six months' renewal notice, for existing capacity on the TransCanada system.

c) Please update Union's filed evidence reflecting all contracts entered into after the filing date, including future service start dates, and term.

Response:

a) Contract term is addressed in the M12 General Terms and Conditions found at:
http://www.uniongas.com/storagetransportation/infopostings/pdf/tariffs/M12_ScheduleA2010.pdf

For convenience, the General Terms & Conditions state:

> ***"ALLOCATION OF CAPACITY***
> *1. A potential shipper may request firm transportation service on Union's system at any time. Any request for firm M12 transportation service must include: potential shipper's legal name, Receipt Point(s), Delivery Point(s), Commencement Date, Initial Term, Contract Demand and proposed payment. This is applicable for M12 service requests for firm transportation service with minimum terms of ten (10) years where Expansion Facilities are required or a minimum term of five (5) years for use of existing capacity."*

b) TransCanada's requirement for term for allocation of existing capacity is described on their web site at:

http://www.transcanada.com/customerexpress/docs/ml_regulatory_tariff/02_TransAccessProc.pdf
For convenience, the Transportation Access Procedures states:

"The Existing Capacity Open Season
(a) TransCanada shall hold an open season for the Existing Capacity (the "Existing Capacity Open Season") commencing on or about May 5 in each calendar year (unless it has no Existing Capacity). The Existing Capacity Open Season shall be for a period of time determined by TransCanada which shall not be less than five (5) Banking Days after the commencement of such Existing Capacity Open Season. TransCanada may hold an additional Existing Capacity Open Season at any time it determines necessary. Service Applicant may during the Existing Capacity Open Season submit by fax or mail a Bid Form for all or a portion of the Existing Capacity for a minimum term of one (1) year. Bids with a term greater than 1 year shall be in full month increments. TransCanada must receive all Bid Forms before the end of such Existing Capacity Open Season."

TransCanada's renewal notice is described on their web site at:
http://www.transcanada.com/customerexpress/docs/ml_regulatory_tariff/05_FTTollSchedule.pdf
For convenience, the FT – Toll Schedules; Renewal Rights state that:

"8. RENEWAL RIGHTS …
Shipper shall have the option (the "Renewal Option") of extending the existing term (the "Existing Term") of the Contract for a period of no less than one (1) year (the "Renewal Term") and revising the Contract Demand to a level no greater than the Contract Demand set out in the Contract (the "Renewal OD") provided that the following conditions are met:

(a) *TransCanada receives written notice from Shipper of Shipper's election to exercise the Renewal Option which sets out the term and Contract Demand of such renewal (the "Renewal Provisions") no less than six (6) months before the termination date which would otherwise prevail under the Contract; and"*

Union takes no position on TCPL's contract language

c) Union has not entered into any new M12 contracts not already included in Union's forecast subsequent to the filing of its application and evidence.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 3, Schedule 5

Union does not forecast any long-term C1 transportation service revenue for the St. Clair to Dawn or Bluewater to Dawn transportation services. Please reconcile this forecast with the ICF market analysis, which states that there will be economic pressure to increase gas flows from Michigan to Ontario to offset declines on the TCPL Mainline (Exhibit A2, Tab 1, Schedule 4, Page 20).

Response:

When Union's 2012 and 2013 S&T forecasts were completed, there were no Long-term C1 Transportation contracts for St. Clair to Dawn or Bluewater to Dawn. Since this time, open seasons were completed on both paths. Please see the responses at Exhibit J.C-4-7-7 a) and Exhibit J.C-4-7-8 b) for results from these open seasons. The impacts to the Short-term Transportation are outlined in Exhibit C1, Tab 3, Table 3.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 3, page 7, Table 2

Please show the annual or forecast M16 transportation revenue for the years 2010 through 2013 year broken out: (a) by customer, and (b) between firm service and interruptible service.

Response:

Union does not track its M16 Transportation revenues as either Firm or Interruptible services. They are tracked as either a demand charge or a variable charge as noted in the following table.

M16 Transportation

Revenue ($ Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
Demand Charges				
Customer A	0.1	0.1	0.1	0.1
Customer B	0.1	0.1	0.1	0.1
Customer C	0.1	0.1	0.1	0.1
	0.3	0.3	0.3	0.3
Variable Charges				
Customer D	0.1	0.1	0.1	0.1
Customer E	0.1	0.1	0.1	0.1
Customer F	0.1	0.1	0.1	0.1
	0.3	0.3	0.3	0.3
Total	$0.6	$0.6	$0.6	$0.6

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 3, pages 3-8

Union has provided the various changes in contracted demand for services on the Dawn-Parkway corridor between 2010 and 2013. In summary, to understand the net effect of these changes on the capacity available, for winters 2012/13 and 2013/14, please provide the forecasted unutilized capacity in the following sections of the system for both a 44 degree day interruptibles off and a 35 degree day interruptibles on:

a) Dawn to Parkway

b) Dawn to Kirkwall

c) Kirkwall to Parkway

Response:

The table below shows the Forecasted unutilized capacity for a 44 degree day interruptibles off.

	44 DD IOFF (GJ/d)	
	Winter 12/13	Winter 13/14
Dawn to Parkway	30,798	209,812
Dawn to Kirkwall	33,600	262,000
Kirkwall to Parkway	230,000	305,000

Union notes that the capacity available on each of the paths identified above is not cumulative, (i.e. Union can sell Dawn to Parkway OR Dawn to Kirkwall OR Kirkwall to Parkway).

The same amount of firm capacity is available on a 35 DD interruptibles on as is noted for the 44 DD IOFF scenario detailed above. M12 contracts for the Dawn to Parkway, Dawn to Kirkwall and Kirkwall to Parkway are not heat sensitive and are not lowered as the degree day is warmer. Union in-franchise customers are heat sensitive and Union does not sell their unutilized capacity (created as temperatures become warmer and they consume less volume) to others on a firm basis.

UNION GAS LIMITED

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

Ref: Exhibit A2, Tab 1, Schedule 1, page 25, line 12

Union states that it "is not projecting optimization revenue as a result of excess Dawn-Parkway capacity due to turnback."

a) Which services does Union include in the definition of "optimization revenue" for transportation assets?

b) Does Union agree that a reduction in the amount of Dawn-Trafalgar capacity sold as long-term firm transportation service will increase the capacity available for sale as short-term firm and interruptible transportation service?

c) Has Union assumed that any Dawn-Trafalgar transportation capacity that will be freed up by non-renewal will have no value as short-term firm or interruptible transportation service? Please explain.

Response:

a) Union includes C1 Short-Term Firm Transportation as optimization revenue for Dawn-Parkway capacity.

b) The reduction in the amount of Dawn-Parkway transportation capacity sold as Long-Term Firm Transportation service could increase the capacity available for sale as Short-Term Firm and Interruptible Transportation service.

c) In the 2013 forecast, the Dawn to Parkway transportation capacity that was not contracted as M12 Long-Term Transportation is not available for sale as it was utilized in the Gas Supply Plan to eliminate Winter Peaking Service requirements, which benefits all Union customers.

   Union is forecasting some available capacity commencing November, 2013. The market for this capacity will be dependent upon TCPL tolls, available downstream capacity and market dynamics.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 3, page 10

We require additional information about Union's forecast of short-term transportation service on the St. Clair/Bluewater system.

a) Please provide a table showing the St. Clair/Bluewater short-term transportation contract demands for 2010 and 2011 by month and by service (i.e. St. Clair to Dawn, Dawn to St. Clair, Bluewater to Dawn, Dawn to Bluewater).

b) Please provide a table showing the St. Clair/Bluewater short-term transportation revenue for 2010 and 2011 by month and by service (i.e. St. Clair to Dawn, Dawn to St. Clair, Bluewater to Dawn, Dawn to Bluewater).

c) Is the jump in 2011 revenue for St. Clair/Bluewater transportation service from the Outlook to the Actual amounts an indicator that the forecasts for 2012 and 2013 should be increased? Please explain.

Response:

a) Please see Attachment 1. St.Clair to Dawn revenues and quantities were not reported in 2010 as they were considered non-utility.

b) Please see Attachment 2.

c) Please see the response at Exhibit J.C-4-1-1.

2010-2011 By Month
Short-Term Transportation Volumes

Line No.	Particulars ('000 GJs)	Path	January	February	March	April	May	June	July	August	September	October	November	December	Total
1	2010 Volumes (1)														
2	C1 Short Term Firm Transportation	Bluewater to Dawn	1,794	576	821	-	-	-	-	854	122	799	3,120	5,409	13,495
3	C1 Short Term Interruptible Transportation	Bluewater to Dawn	451	274	168	845	157	137	17	-	-	34	-	-	2,083
4			2,245	850	989	845	157	137	17	854	122	833	3,120	5,409	15,578
5	2011 Volumes														
6	C1 Short Term Firm Transportation	Bluewater to Dawn	4,641	2,867	4,369	1,251	3,253	1,639	1,924	-	425	570	3,935	5,666	30,540
7	C1 Short Term Interruptible Transportation	Bluewater to Dawn	-	-	-	2,081	-	2,110	-	55	-	-	-	-	4,246
8	C1 Short Term Firm Transportation	St. Clair to Dawn	1,948	2,195	2,770	1,266	1,481	654	-	74	1,266	2,068	5,516	6,367	25,605
9	C1 Short Term Interruptible Transportation (2)	St. Clair to Dawn	63	-	11	-	21	-	-	42	-	675	-	-	812
10			6,652	5,062	7,150	4,598	4,755	4,403	1,924	171	1,691	3,313	9,451	12,033	61,203

Filed: 2012-05-04
EB-2011-0210
J.C-4-10-5
Attachment 2

2010-2011 By Month
Short-Term Transportation Revenue

Line No.	Particulars ($000's)	Path	January	February	March	April	May	June	July	August	September	October	November	December	Total
1	2010 Revenue														
2	C1 Short Term Firm Transportation	Bluewater to Dawn	104	106	102	-	-	-	-	42	6	39	120	205	724
3	C1 Short Term Interruptible Transportation	Bluewater to Dawn	34	21	12	60	11	8	1	-	-	2	-	-	149
4			138	127	114	60	11	8	1	42	6	41	120	205	873
5	2011 Revenue														
6	C1 Short Term Firm Transportation	Bluewater to Dawn	173	111	160	63	151	76	96	-	22	30	210	302	1,394
7	C1 Short Term Interruptible Transportation	Bluewater to Dawn	-	-	-	146	-	27	-	4	-	-	-	-	177
8	C1 Short Term Firm Transportation	St. Clair to Dawn	179	175	227	89	95	39	-	5	109	119	430	473	1,940
9	C1 Short Term Interruptible Transportation	St. Clair to Dawn	5	-	1	-	2	-	-	3	-	3	-	-	14
10			357	286	388	298	248	142	96	12	131	152	640	775	3,525

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 3, page 11-13

We require additional information about Union's Exchange Revenue forecast.

a) Is Exchange Revenue derived entirely from the use of Union's contracted capacity on upstream transporters, or does it also involve the use of Union's own transmission assets?

b) For each year from 2010 through 2013, please provide the actual or forecast net revenue from upstream transportation capacity release or assignment, by pipeline.

c) For each year from 2010 through 2013, please provide the actual or forecast net revenue from third-party exchanges.

d) For each year from 2010 through 2013, please provide the portion of the total net revenue from third-party exchanges that resulted from the TCPL FT RAM program.

Response:

a) Exchange revenue is generated using capacities on upstream transportation assets as well as Union's own transmission assets.

b) Please see the response at Exhibit J.C-4-7-9 e).

c) Please see the response at Exhibit J.C-4-7-9 e).

d) Please see the response at Exhibit J.C-4-7-9 e).

UNION GAS LIMITED

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

Ref: Exhibit A2, Tab 1, Schedule 1, page 7, line 7

Union states that "[w]ith the expected elimination of TCPL FT RAM credits in November, 2012, Union's ability to earn revenue from upstream capacity is severely limited."

a) Please provide Exchange Revenue forecasts for 2012 and 2013 with the assumption that the FT RAM program continues in its current form through the end of 2013.

Response:

Please see the response at Exhibit J.C-4-7-9 c).

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 3, page 11

Union states "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."

Since the purpose of FT-RAM is to mitigate the cost of holding long-haul transportation capacity, please provide:

a) Union's explanation of why the net revenues generated from RAM are streamed to Exchange Revenue as opposed to being recognized as a credit to the cost of long-haul TCPL service that is charged to customers.

b) The specific Board approval of a Union Gas request for this treatment of FT-RAM credits.

Response:

a) Net revenues generated from RAM are recorded as Exchange Revenue since this is the service type under which they are contracted and sold.

   Union's use of the RAM program was based on Union's IR mechanism per EB-2007-0606 and was further confirmed in the Board's Decision on Union's 2009 Rates Application per EB-2008-0220. The IR mechanism defined the parameters for earnings sharing, the principles of which were confirmed in practice in the EB-2008-0220 with respect to the DOS-MN service. Union applied these approved parameters to revenues generated through the RAM program.

   Specifically, in EB-2008-0220, the Board agreed that "benefits resulting from transactions to optimize transportation capacity…are recognized as part of Union's regulated S&T transactional activity", and that "the forecast margin for [this] activity included in rates was increased significantly in the 2007 rates settlement agreement". This provided "ratepayers with a fixed level of benefits from S&T transactional activity, and provided Union with a strong incentive to exceed that level of fixed benefit. Union is at risk for achieving the forecast results and is only rewarded if the net benefits exceed the threshold incorporated in rates".

In its decision, the Board stated "ratepayers have been already credited with an amount intended to reflect the transactional services activity of the company. Any additional revenues which may be occasioned by the new TransCanada [DOS-MN] service will not accrue under this heading, but may lead to earnings sharing distribution. In the Board's view this is a fair approach that is consistent with the general architecture of the IRM plan and the Settlement Agreement."

b) In Union's view, the RAM program provides comparable revenue opportunities to the DOS MN program and it is appropriate to account for these revenues in the same way.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 3, pages 14-17

We require additional information about Union's short-term peak storage revenue forecast.

a) Please explain why Union has assumed that all of the 13.0 PJ of Excess Utility storage space will be sold as short-term peak storage in 2013.

b) Given that the in-franchise requirement for storage has decreased since the NGEIR Decision was issued in 2006, is there anything that prevents Union from selling a portion of the Excess Utility space as long-term firm storage service?

c) Is the value of the available Excess Utility storage space maximized by selling all of the capacity as short-term peak storage service, or would Union be able to obtain greater value for the available Excess Utility storage space on behalf of ratepayers by selling this capacity using a mix of short-term peak storage service and long-term firm storage service?

d) Union states that the average price for short-term peak storage contracts was $1.39/GJ in 2010 and $0.66/GJ in 2011, and that it expects the average price to be $0.55/GJ in 2012 and $0.85/GJ in 2013. Please provide the corresponding actual and projected average prices for long-term firm storage contracts (i.e. 2 years or longer) for each of these years.

e) Please describe how Union optimizes utility storage assets that are required for in-franchise services on a design-year planning basis (i.e. are not included in Excess Utility storage space), but are available for sales as ex-franchise services on daily, monthly, or seasonal basis.

f) Please identify, by service, the storage and balancing service revenue that Union received in 2010 and 2011 using utility storage space that is not included in Excess Utility storage space.

Response:

a) The amount of excess utility storage space fluctuates year over year. Union is required to have 100 PJ of storage available, at cost, each year for in-franchise use. By contracting on a short-term basis, Union ensures that the entire 100 PJ is available for in-franchise use each year should it be required.

b) Please see response at a) above.

c) Union's experience has been that generally short-term peak storage sells at a premium to long-term storage. Please see the response to a) above.

d) Please see Attachment 1.

e) Union markets off-peak storage, balancing and loan services during off peak periods. Union sells these services on a daily, monthly or seasonal basis to the extent that the cost to provide these services is less than the value Union can extract from the market. The services are marketed to all Union's customers, in-franchise and ex-franchise.

f) Revenue related to short-term peak storage and balancing services is found in Exhibit C1, Tab 3, p. 15. The short-term storage and balancing services were provided by using both Excess Utility space and available Non-Utility space.

UNION GAS LIMITED
Southern Operations Area
Average Value of Long-term Peak Storage

Particulars	Actual 2008 ($ CDN/GJ)	Actual 2009 ($ CDN/GJ)	Actual 2010 ($ CDN/GJ)	Actual 2011 ($ CDN/GJ)
Long Term Peak Storage	1.25	1.35	1.05	0.80

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 3, pages 14-17

We require additional information about Union’s revenue forecast for off-peak storage, balancing and loans.

a) For Table 5 on Page 15, please break out the revenue for “Off-peak storage, Balancing and Loans” to show each of the individual services (i.e. Off-Peak Storage, Supplemental Balancing Services, Gas Loans, Enbridge LBA).

b) Please provide a table showing actual Short-term storage revenue by month for 2011, using the same format as Exhibit B3.5 in EB-2011-0038.

c) Please provide a table showing actual Short-term storage services quantities by month for 2011, using the same format as Exhibit B3.6 in EB-2011-0038.

d) Please describe the services that are included in Supplemental Balancing Services. Who are the customers for these services?

Response:

a) Please see Attachment 1.

b) Please see Attachment 1.

c) Please see Attachment 2.

d) Supplemental balancing services include Basic Hub balancing and enhanced Hub balancing services. These services have a storage and a loan component and customers can hold a balance within a range, positive or negative. Any customer of Union’s can hold a Hub contract. It is a requirement that ex-franchise shippers and market based storage customers hold a Hub contract.

Short-term Storage and Balancing Revenue

Revenue ($ Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
Short-term peak storage	$ 14.9	$ 9.0	$ 6.6	$ 9.0
Off-Peak Storage	1.7	0.3	0.5	0.5
Supplemental Balancing Services	3.3	1.4	2.0	2.0
Gas Loans	0.9	0.1	-	-
Enbridge LBA	0.1	0.1	-	-
Total	$ 20.9	$ 10.9	$ 9.1	$ 11.5

UNION GAS LIMITED
Short-Term Storage Services Summary For Year 2011

Line No.	Storage Space (GJ)	Jan-11 (a)	Feb-11 (b)	Mar-11 (c)	Apr-11 (d)	May-11 (e)	Jun-11 (f)	Jul-11 (g)	Aug-11 (h)	Sep-11 (i)	Oct-11 (j)	Nov-11 (k)	Dec-11 (l)
1	Peak Short-Term Storage	10,243,032	10,243,032	12,338,144	10,178,032	12,223,144	13,243,200	12,133,144	11,103,088	10,073,032	10,073,032	13,238,200	13,238,200
2	Off-Peak Short-Term Storage	-	-	-	1,055,056	1,266,067	2,321,123	2,321,123	1,266,067	1,055,056	1,055,056	-	527,528
3	Parking Services	-	1,716,434	2,171,163	2,171,163	2,997,166	3,419,189	3,419,189	1,248,025	1,248,025	-	-	1,181,663
4	Total	10,243,032	11,959,466	14,509,307	13,404,251	16,486,377	18,983,512	17,873,456	13,617,181	12,376,113	11,128,088	13,238,200	14,947,391

Line No.	Maximum Daily Injection (GJ/day)	Jan-11 (a)	Feb-11 (b)	Mar-11 (c)	Apr-11 (d)	May-11 (e)	Jun-11 (f)	Jul-11 (g)	Aug-11 (h)	Sep-11 (i)	Oct-11 (j)	Nov-11 (k)	Dec-11 (l)
5	Peak Short-Term Storage	16,090	16,090	16,090	4,484	4,484	4,484	17,567	614	614	-	-	-
6	Off-Peak Short-Term Storage	-	-	-	-	-	-	-	-	-	-	-	31,652
7	Parking Services	-	110,334	-	-	316,516	-	-	-	-	-	-	-
8	Loan Services	-	-	-	35,169	-	500	-	-	-	-	17,296	44,523
9	Total	16,090	126,424	16,090	39,653	321,000	4,984	17,567	614	614	-	17,296	76,175

Line No.	Maximum Daily Withdrawal (GJ/day)	Jan-11 (a)	Feb-11 (b)	Mar-11 (c)	Apr-11 (d)	May-11 (e)	Jun-11 (f)	Jul-11 (g)	Aug-11 (h)	Sep-11 (i)	Oct-11 (j)	Nov-11 (k)	Dec-11 (l)
10	Peak Short Term Storage	(127,290)	(127,290)	(57,553)	(42,466)	(146,917)	(159,578)	(145,598)	(132,937)	(132,937)	(132,937)	(132,937)	(132,937)
11	Off-Peak Short Term Storage	-	-	-	-	-	-	-	-	-	-	-	-
12	Parking Services	-	-	-	-	-	-	(70,037)	-	(22,258)	-	-	-
13	Loan Services	-	-	-	-	-	-	-	-	(35,133)	(49,650)	-	-
14	Total	(127,290)	(127,290)	(57,553)	(42,466)	(146,917)	(159,578)	(215,636)	(132,937)	(190,329)	(182,587)	(132,937)	(132,937)

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference: Exhibit C1, Tab 3

Union has indicated that it is reducing its exchange revenues forecast for 2013 due to TCPL's proposed elimination of its FT-RAM program:

a) Please describe in detail how Union was able to generate revenue from this program.

b) TCPL in its filing with the National Energy Board[1] indicates that there are other ways to alleviate the impact of the elimination of RAM including increased diversions, use of alternate receipt points and increased use of other services, and as such IT and STFT. Given that the use of these alternate strategies will very likely include increased transportation to and from Dawn, has Union incorporated any additional short term transportation revenue or exchange revenue to reflect the mitigating strategies that TCPL is suggesting will be a market response as a result of the elimination of its FT-RAM program. Please explain.

Response:

a) Please see the response at Exhibit J.C-4-7-10 a).

b) There are a number of different proposals before the NEB. Union has no way of accurately forecasting which proposal, or portions of proposals, will ultimately be approved and implemented. As well, it would be very difficult to accurately forecast specific impacts to Union's throughputs. However, the 2013 exchange forecast is higher than historical years prior to Union's use of the TCPL FT RAM program due to forecasted growth in activity. Please see Exhibit C1, Tab 3, pp. 12-13.

[1] RH-3-2011 Section 8.0 Page 28

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPRO")

Reference: Exhibit C1, Tab 3, Page 10, Table 3
Exhibit A2, Tab 1, Schedule 1, Pg 12, Table 4

Union is not forecasting any increase in Dawn-Parkway short term revenue in 2013. In A2, it is indicated that there is in excess of 1 PJ of available Dawn-Trafalgar capacity. In addition, it appears that Union will access Marcellus gas and downstream winter markets through bi-direction flow capability at Kirkwall and bidirectional flow capability at the downstream export points at Niagara. Please explain why Union would not expect to see some short term sales using this excess 1 PG/d of capacity?

Response:

Exhibit A2, Tab 1, Schedule 1, Table 4, line 6, column c) indicates that the cumulative impact of M12 Transportation turnback is 1,045,386 GJ from 2011-2013. Please see Exhibit C1, Tab 3, Schedule 3 for a summary of the treatment of M12 transportation turnback.

Please see the response at Exhibit J.C-4-10-4 b) & c) for the impact of turnback on the short-term transportation forecast.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit C1, Tab 3
Exhibit C1, Summary Schedule 5

Please provide an exhibit that broadens Summary Schedule 5 to include Actual information for each of the line items 1 to 13 inclusive for the years 2007, 2008 and 2009.

Response:

Please see the response at Exhibit J.C-4-5-2.

UNION GAS LIMITED

Answer to Interrogatory from
Canadian Manufacturers & Exporters ("CME")

Ref: Exhibit C1, Tab 3
Exhibit C1, Summary Schedule 5

What is the level of S&T capacity utilization Union is forecasting for 2013 compared to the actual level of S&T capacity utilization achieved in each of the prior years 2007 to 2012 inclusive?

Response:

Please see Attachment 1 for S&T capacity utilization for Dawn to Parkway, Dawn to Kirkwall, St. Clair to Dawn, Bluewater to Dawn and Ojibway to Dawn for 2007-2013 based on ex-franchise activity.

Annual S&T Capacity Utilization
Transportation Service [1]

Line No.		2007	2008	2009	2010	2011	Forecst 2012	Forecast 2013
1	Dawn to Parkway [2]	25%	28%	29%	42%	38%	51%	44%
2	Dawn to Kirkwall	50%	46%	30%	31%	16%	23%	13%
3	St.Clair to Dawn [3]	5%	14%	12%	9%	34%	0%	0%
4	Bluewater to Dawn	13%	10%	15%	20%	45%	48%	48%
5	Ojibway to Dawn	23%	24%	47%	54%	51%	39%	40%

Note:
(1) Represents nominated S&T activity and does not include utility activity.
(2) Dawn to Parkway includes interruptible transportation forecast for 2012 and 2013.
(3) St. Clair to Dawn activity is included with Bluewater to Dawn for 2012 and 2013 forecast.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exh C4/Tab 1/Sched.1

Union's update of March 27, 2012 revised Other Operating Revenue from $1.222 million to 2.413 million.

a) Please provide the reasons for the significant revision to Other Operating Revenue.

b) Is this increase in revenue likely to continue into 2012 and 2013?

Response:

a) The actual results for 2011 exceeded the outlook as result of an accounting adjustment for unclaimed cheques outstanding greater than 2 years.

b) Union does not forecast these revenues as annually recurring items as it cannot predict the timing and dollars associated with unclaimed cheques and do not consider the annual dollar amounts to be material. Union also expects the dollar amount for unclaimed cheques to decrease as we move more to electronic payments. As of December 31, 2011, the general ledger balance for outstanding cheques is: 6-12 months , $156,000; 12-18 months, $223,000; 18-24 months, $129,000.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 4, Updated

a) The evidence at line 13 of page 1 indicates that there was 315,202 direct purchase customers at January, 2011. Please provide the number of direct purchase customers for the most recent month where the information is available.

b) The evidence at lines 2 through 5 of page 2 indicates the methodology used to forecast billing revenues related to direct purchase customers. Please update the forecast to reflect the most recent direct purchase customer count. What is the impact on the 2012 revenue forecast of this update?

Response:

a) As of March 31, 2012 there were 222,958 general service customers on direct purchase.

b) If Union were to update the forecast to recognize customer migration from direct purchase general service to sales service through March 31, 2012, holding that customer count constant from April – December 2012:

   i) Revenues would decrease by $0.8 million as a result of lower direct purchase administration charges partially offset by higher gas supply administration charges (based on January 1, 2011 rates).

   ii) Gas supply revenue would increase to reflect a higher number of system sales customers

   iii) The revenue requirement would increase by a like amount in cost of gas as well as a minor impact to rate base for the increased inventory and changes to cash working capital resulting in a net decrease to the expected sufficiency in 2012.

UNION GAS LIMITED

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

Ref: Exhibit C1, Summary Schedule 6, Updated

a) Please explain the significant drop for delayed payment charges shown for 2010 in Summary Schedule 6.

b) Please explain what is driving the reduction in mid market transaction revenues shown in Summary Schedule 6 for 2011 through 2013 relative to the levels recorded in 2007 through 2010.

c) Please explain the significant increase in 2011 for other operating revenue and explain why the level is forecast to drop in 2012 by about 50%.

Response:

a) Delayed payment charges are calculated on total dollar amount in arrears which is directly related to the total amount of the customer bill.

   The average annual residential bill in 2010 was $743, the lowest of the last 5 years. This was the result of:

   - Warmer weather;
   - Falling natural gas prices; and
   - Union proactively working with customers coming out the recession to assist them with payment arrangements.

   Warmer than budget weather not only reduces the amount of gas consumed, but it can result in customers on the equal billing plan being in a credit position and not subject to delayed payment charges. This was the case in 2010 when, following a warmer than budget fall in 2009 and winter in 2009/2010, a significant portion of our Equal Billing Plan customers (approx. 35% of our customer base) were in a credit position when their plans renewed in August.

b) In 2007, mid market revenues peaked at $3.7 million driven largely by the use of storage services and the clearing of the Other Direct Purchase Services deferral account into revenue. In 2007, storage related revenues (T1 incremental storage, Banked Gas Account

(BGA) Overrun and BGA HUB services) were $0.5 million higher than the average for 2008-2010. In addition, the final clearing of the Other Direct Purchase Services deferral account increased revenues by $0.8 million in 2007. (Note: the Other Direct Purchase Services deferral account was closed January 1, 2008 per EB-2007-0606)

For the period of 2008-2010 mid market revenues were relatively flat ($2.1 - $2.3 million). This was followed by a significant decline in 2011 to $1.3 million. The major variance in 2011 was a reduction in the use of storage services, $(0.8) million relative to the prior 3 years, most notably the commodity balancing service (CBS) and BGA overrun and BGA HUB services. This reduction is supported by two key market factors: higher consumption resulting from colder than normal weather; and, the customer's ability to economically balance consumption variances by buying / selling natural gas in lieu of purchasing balancing services.

The 2012 and 2013 mid market transactions forecast is $2.0 million. This forecast was developed with consideration to trends in customer behaviour, service fees an historic activity

c) Please refer to interrogatory J.C-5-1-1 a) and J.C-5-1-1 b).

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.

UNION GAS LIMITED
Miscellaneous Non-Energy Charges

Line No.	Service ($000's)	Fee	2010 Revenue	2011 Revenue
	Residential Customer Class Service			
1	Connection Charge & Landlord Turn-on [1]	$35	5,409	5,350
2	Temporary Seal - Turn-off (Seasonal)	$22	23	19
3	Temporary Seal - Turn-on (Seasonal)	$35	30	32
	Commercial/Industrial Customer Class Service			
4	Connection Charge & Landlord Turn-on	$38	248	283
5	Temporary Seal - Turn-off (Seasonal)	$22	4	6
6	Temporary Seal - Turn-on (Seasonal)	$38	8	10
	Residential/Commercial/Industrial Customer Class Service			
7	Disconnect/Reconnect for Non-Payment [2]	$65	858	886
	Statement of Account/History Statements			
8	History Statement (previous year and beyond previous year) [3]	$15/statement previous year & $40/hour beyond previous year	9	8
9	Duplicate Bills * (if manually processed)	$15/statement	0	0
	Dispute Meter Test Charges			
10	Meter Test - Residential/Commercial/Industrial Meter [4]	$50 flat fee for removal and test Residential and Hourly charge based on actual costs Commercial/Industrial	0	1
	Direct Purchase Administration Charges			
11	Monthly fee per bundled t-service contract or unbundled U2 contract	$75.00	812	774
12	Monthly per customer fee	$0.19	811	648
13	Invoice Vendor Adjustment (IVA) fee (for each successfully submitted IVA transaction)	$1.09	7	7

Notes:
(1) Includes lines 1 and 4 from Exhibit A1 Tab 13, Schedule 2
(2) Includes lines 5 and 10 from Exhibit A1 Tab 13, Schedule 2
(3) Includes lines 11 and 12 from Exhibit A1 Tab 13, Schedule 2
(4) Includes lines 15 and 16 from Exhibit A1 Tab 13, Schedule 2

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 4, page 2

The evidence states that the 2012 forecast customer count, based on Union's established forecasting methodology for billing revenues, holds the direct purchase general service customer count constant at January 2011 for forecast period. Please explain why the customer count is not updated to reflect the most recent actuals. What would be the impact on the revenue requirement is this update was undertaken?

Response:

The most recent actual data available when preparing the 2012 forecast was for the 2010 calendar year. This supported our using the January 2011 direct purchase general service customer count. Please see the response at Exhibit J.C-5-2-1 b) in response to the revenue requirement impact if an update was undertaken.

UNION GAS LIMITED

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

Ref: Exhibit C1, Summary Schedule 6

Please explain why, with respect to every component of Other Revenue, the 2007 actuals were greater than the Board approved levels.

Response:

Delayed Payment Revenue
In the winter of 2007 normalized average consumption exceeded forecast. This would have resulted in higher customer bills and higher late payment fees.

Account Opening Charges
The 2007 forecast was prepared at a macro level based on single service, customer attachments, whereby an average per customer connection charge was multiplied by the forecasted number of customer attachments. There are a number of services which contribute to account opening charges: customer attachments, customer moves, seasonal meter turn on and turn offs and credit turn-on's.

In comparing 2007 actual results to forecast, our customer attachment forecast was in decline and the forecast methodology did not consider the potential offsetting impacts of the two other services. As a result, the 2007 forecast underestimated the revenues for that year.

The forecast methodology was changed for 2012 and 2013 and now considers the three variables.

Billing revenue
The 2007 forecast for billing revenue was based on a DP customer count of 460,669. At 2007 year-end, the actual number of general service customers having elected to migrate from system sales service to direct purchase was 463,516. This variance supports the revenue variance between 2007 forecast and actual.

Mid Market Transactions
Please refer to J.C-5-2-2 b).

Other Operating Revenue

The $1.4 million variance is comprised of three unforecasted revenue items – moving deferred revenues into income on a one time basis, a true-up of unclaimed cheques, 3rd party service / consulting fees.

UNION GAS LIMITED

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

Ref: Exhibit C1, Summary Schedule 6

Please explain what Mid-Market transactions are and how Union forecasts this revenue item.

Response:

Mid market transaction revenues are fees for services used by direct purchase customers to allow them to meet contract requirements in response to unplanned variances in consumption / production. The forecast for mid market transactions is developed with consideration of trends in customer behaviour, service fees and historic activity. Factors that affect balancing revenues are:

- weather variances;
- unplanned production variances;
- customer understanding of balancing options and fees (increased knowledge results in customers optimizing costs); and
- market alternatives.

More information on balancing transactions, types and fees can be found on our website at:
www.uniongas.com/business/accountservices/unionline/contractsrates/services/balancinginfo.asp

UNION GAS LIMITED

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

Ref: Exhibit C1, Summary Schedule 6

Please explain what is included in Other Operating Revenue and how Union forecasts this revenue item.

Response:

Other operating revenue is comprised of items that have a relatively small dollar value (i.e. less than $100,000 annually), are one-time in nature, or unrelated to Union's core business. The forecast is developed based on an itemized review of historic actual other operating revenues with consideration to whether the revenues would recur in the forecast period and materiality.

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Ex.C1/Summary Schedule 6.

One source of other revenue included on the table referenced is labelled "Mid market transactions".

a) Please explain what "mid market transactions" are.

b) In the initial filing, "mid market transactions" revenues for 2011 were forecast at $1.9 million. In the March 27th update, 2011 revenues for this line item are reported at approximately $1.3 million. Please explain the drivers for the change.

Response:

a) Please see the response at Exhibit J.C-5-5-3.

b) Please see the response at Exhibit J.C-5-2-2 b).

UNION GAS LIMITED

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

Ref: Exhibit H1, Tab 1, page 10

Please explain why Union has determined that the interruptible M16 rate is the applicable charge for Union's use of utility transmission assets to transport gas between Heritage storage and Dawn.

Response:

As described at Exhibit H1, Tab 1, Updated, pages 7 and 8, to ensure Union's unregulated storage operations are allocated costs associated with the Heritage Storage pool's use of regulated transmission assets, Union is proposing to charge its unregulated storage operations both the transmission commodity and fuel charges per the proposed M16 rate schedule.

As Union's unregulated business owns and operates the customer station at the Heritage Storage pool, the M16 monthly fixed charge per customer station is not applicable. Further, as the Heritage Storage pool transports gas to and from Dawn on an interruptible basis only, the M16 monthly firm demand is not applicable.

Union's unregulated storage operations are paying the utility for the services provided by regulated transmission assets.

UNION GAS LIMITED

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

Ref: Exhibit H1, Tab 1, page 10

Please show what the credit amount would be using the M16 firm transportation rates and the maximum daily withdrawal and maximum daily injection capacities of the Heritage pool.

Response:

Please see the response at Exhibit J.H-11-2-1 b).

UNION GAS LIMITED

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

Ref: Exhibit H1, Tab 1, page 10

For each winter since the pool was in service, please provide the specific number of interruptions that were called on the following pools:

a) Heritage Pool

b) Sarnia Airport Pool

Response:

No interruptions have been called on the Heritage or Sarnia Airport pools.

UNION GAS LIMITED

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

Ref: Exhibit A1 Tab 9, page 1

We require additional information about the S&T services Union provides to its affiliate Sarnia Airport Pool, L.P.

a) At what location do Union's facilities interconnect with the Sarnia Airport Storage Pool transmission line?

b) Please describe the firm and/or interruptible transportation and compression services that Union provides for Sarnia Airport Storage Pool.

c) Please describe any other services that Union provides for Sarnia Airport Storage Pool.

d) What facilities does Union utilize to provide transportation and balancing services for Sarnia Airport Storage Pool?

e) What was the total quantity of gas that Union delivered to Sarnia Airport Storage Pool in 2011?

f) What was the total quantity of gas that Union received from Sarnia Airport Storage Pool in 2011?

g) What revenue did Union received from Sarnia Airport Storage Pool in 2011 for (a) transportation services under Rate Schedule M16, (b) transportation service under other rate schedules, (c) storage and balancing services, and (d) other services?

Response:

a) Union's facilities interconnect with the Sarnia Airport Storage Pool transmission line at Mandaumin/Bluewater measurement and control station.

b) The regulated services that Union provides are interruptible HUB balancing and M16 interruptible transportation.

c) Please see the response at b) above.

d) The facilities used for the transportation service are the same facilities used by Union to transport Bluewater and Mandaumin storage pool gas to and from Dawn. The balancing services are provided using Union's integrated storage assets.

e) The total gas Union delivered to Sarnia Airport Storage Pool in 2011 was 120,723 10^3m^3.

f) The total gas Union received from Sarnia Airport Storage Pool in 2011 was 105,842 10^3m^3.

g) Revenue received from the regulated services:

	2011 ($000's)
M16 West Transportation	119
Balancing	3
Total	122

UNION GAS LIMITED

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

Ref: Exhibit C3, Tab 4, Schedule 3
EB-2011-0038, Exhibit B3.4

We require additional information about the company-owned storage and 3rd party storage services that comprise Union's integrated storage operation.

a) Please fill in the empty cells in the table below:

(TJ)	2010	2011	2012	2013
Base	163,700			
(Unavailable)	(700)			
LNG	600	600	600	600
3rd Party	14,600			
Total Storage Space	178,300			
Union Requirement	60,500	63,856	61,659	61,383
Contract Carriage	19,700	16,594	16,188	16,113
System Integrity	9,700	9,527	9,527	9,527
Excess Utility Storage	10,100	10,023	12,627	12,977
Total Utility Storage	100,000	100,000	100,000	100,000
Non-Utility Storage	78,300			

b) Please identify each of the storage operators from whom Union purchased 3rd party storage services in 2011.

c) For each 3rd party storage service, please identify the location(s) at which natural gas is delivered to, or received from, the 3rd party storage operator.

d) For any 3rd party storage services for which the receipt point or delivery point is not Dawn (e.g. MichCon, Washington 10), please describe the transportation arrangements used to transport gas between the 3rd party storage service and Dawn. Please state whether deliveries for withdrawal and injection are firm or interruptible, the maximum daily quantity of firm transportation used to transport gas to and from Dawn, the transportation contracts that are used, and whether Union has acquired separate transportation contracts for its non-utility storage operation.

Response:

a) and b)

For storage activities related to the regulated business, the Black Creek storage service is provided by Enbridge Gas Distribution and the contracted quantity is 1.069 PJ for 2011, 2012, and 2013. The storage costs for Black Creek are split between Utility and Non-Utility in the same ratio as Union's overall storage portfolio.

Other third party storage contracts are part of Union's unregulated business and are not relevant to Union's 2013 regulated rates.

c) Union delivers gas to Black Creek at Enbridge SWDA. Union receives gas from Black Creek at Tecumseh.

d) For the Black Creek storage facility, Union has contracted for firm Rate 325 (Transmission, Compression and Pool Storage Service) with Enbridge to transport gas between Black Creek and Dawn for a maximum firm quantity of 283 10^3m^3/day. The transport costs for Black Creek are split between Utility and Non-Utility in the same ratio as Union's overall storage portfolio.

In addition, Union has a long standing, blanket interruptible backhaul contract with TCPL which may also be used to facilitate Black Creek storage pool injections by transporting gas from Dawn to Tecumseh on TCPL. This contract is used and invoiced on an as-needed basis.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 6, page 2, line 18

If Union's non-utility storage operation encroached on utility storage space, and Excess Utility storage space was available, as Union states, please explain why Union's non-utility storage operation did not purchase a short-term storage or parking service from the utility storage operation.

Response:

Union did not purchase a short-term storage or parking service from the utility operation as Union continues to be responsible for ensuring the forecast space is available for in-franchise customers throughout the injection season. If Union were to "buy" a service from the utility operation, in order to provide the same service reliability that is available from third party providers, the utility operation would have to reduce the in-franchise storage space entitlements for the remainder of the injection season to make room for the equal volume of firm non-utility gas. By purchasing a third party service, Union was assured of the service reliability, and has established the market value of the service.

UNION GAS LIMITED

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

Ref: Exhibit C1, Tab 7

We require additional information about Union's proposal to allocate short-term storage revenue between utility and non-utility operations.

a) Please explain why this proposed allocation is necessary if Union is able to track the short-term storage sold from non-utility storage space.

b) Is Union proposing to make the same allocation for long-term firm storage services?

c) Under the current regulatory construct, how can the Board be assured that revenues from short-term storage services sold from excess utility storage to shippers who have long-term storage and/or HUB contracts are collected in deferral account 179-70?

d) Under Union's proposed allocations, please provide Union's specific proposal on to deem how much space was used for each of Off-peak Storage, Gas Loans, Enbridge LBA, Supplementary Balancing Services and C1 Firm Short-Term Deliverability? Please provide a description and specific numeric examples for each.

Response:

a) Please see the response at Exhibit J.DV-1-1-1.

b) No.

c) Union tracks revenues by service type, not by customer. All short-term storage revenues are allocated to the short-term storage service in Union's revenue tracking system.

d) Union is not proposing to treat Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing Services and C1 Firm Short Term Deliverability any differently than it does currently. Please see the response at Exhibit J.DV-1-1-1.