

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

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

**CANADIAN MANUFACTURERS & EXPORTERS (“CME”)
COMPENDIUM OF DOCUMENTS
REVENUE: IN FRANCHISE**

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UNION GAS LIMITED
Revenue Deficiency/Sufficiency Components

Line No.	Particulars (\$ millions)	(1) 2007 BA vs 2007	(2) 2008 vs 2007 BA	(3) 2009 vs 2007 BA	(4) 2010 vs 2007 BA	(5) 2011 vs 2007 BA	(6) 2012 vs 2007 BA	(7) Total Col (1) to (6) inclusive
Revenue:								
1	Contract Market	(11)	(9)	(5)	(3)	(3)	5	(26)
2	General Service Market	6	(10)	(11)	0	(17)	(19)	(51)
3	S&T	(3)	(37)	(42)	(41)	(45)	(34)	(202)
4	Other Revenue	(5)	(2)	(2)	1	1	1	(6)
5	Sub-Total: Net Revenue	(13)	(58)	(60)	(43)	(64)	(47)	(285)
6	Delivery-related Gas Costs:	9	(16)	1	(38)	(46)	(42)	(132)
O&M:								
7	Compensation	5	8	12	38	57	54	174
8	Contract Services	2	7	7	9	15	18	58
9	DSM Programs			2	4	5	11	22
10	Outbound Affiliates	(1)	(1)	(3)	(4)	(6)	(8)	(23)
11	Bad Debt	(4)	(2)	(2)	(6)	(7)	(5)	(26)
12	Capitalization	4	(3)	(1)	(2)	(9)	(11)	(22)
13	Non-Utility Allocations		(3)	(7)	(6)	(7)	(7)	(30)
14	Other	(12)	(8)	(14)	(7)	(2)	6	(37)
15	Sub-total: Net O&M	(6)	(2)	(6)	26	46	58	116
16	Other Expense			3	0	(1)	0	2
17	Rate Base Growth Net of Tax Changes & Debt Costs	(14)	(11)	12	11	11	27	36
18	ROE Formula Change		5	(1)	0	(8)	(8)	(12)
20	Revenue Deficiency/Sufficiency	(24)	(82)	(51)	(44)	(62)	(12)	(275)

UNION GAS LIMITED

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

Ref: Exhibit A2, Tab 1
Exhibit F5, Tab 1, Schedule 1
Exhibit F4, Tab 1, Schedule 1

At Exhibit A2, Tab 1, page 2 and throughout the filing, elements of the proposed 2013 revenue requirement are compared to elements of the 2007 Board Approved revenue requirement. Based on information in Table 3 of Exhibit A2, Tab 1, Schedule 1, at page 6, the revenue sufficiencies for 2008, 2009 and 2010 are \$82.3M, \$51.6M and \$44.1M respectively. For 2011, the revenue sufficiency shown in Exhibit F4, Tab 1, Schedule 1 is \$29.9M, and for 2012, it is about \$2.6M as shown in Exhibit F5, Tab 1, Schedule 1. The total of revenue sufficiencies over 5-years is about \$210.5M, or on average \$42.1M per year.

In order to enable us to evaluate the appropriateness of the revenue requirement and revenue deficiency amounts Union asks the Board to approve for 2013 and, in particular, whether the gains achieved under Incentive Regulation are reflected in Union's proposed 2013 revenue requirement, what we seek is a spreadsheet presentation that starts with the elements of the Board Approved 2007 revenue requirement and then tracks the causes of the revenue requirement sufficiencies achieved year-by-year from 2007 to 2012 inclusive so that all of this information can be considered alongside the elements of the proposed revenue requirement for 2013.

In this connection, would Union please provide the following:

- a) A summary schedule in spreadsheet format that starts with a column equivalent to lines 1 to 21 inclusive of Column (b) in Exhibit A2, Tab 6, Schedule 1, page 3, showing the major elements of the EB-2005-0520 Approved revenue requirement, to be followed by columns containing the information at lines 1 to 21 inclusive for Actual Years 2007 to 2012 inclusive; followed by the information shown in Column (a) in Exhibit A2, Tab 6, Schedule 1, page 2 for 2013 Proposed showing a revenue deficiency in the amount of \$65.611M. This presentation will then show the Proposed 2013 Revenue Requirement and Deficiency alongside the Revenue Sufficiency amounts commencing with 2007 Actual and culminating with the 2012 Estimated Actual amount.
- b) For each of the columns 2007 Actual to 2012 Estimated Actual, please provide the following additional information in a "Revenue Deficiency/Sufficiency" format similar to Exhibit A2, Tab 6, Schedule 2, including a brief description by line item of the causes for:
 - i. 2007 Actuals being less than 2007 Board Approved elements of the revenue requirement presentation;
 - ii. 2008 Actuals differing from 2007 Actuals;
 - iii. 2009 Actuals exceeding 2008 Actuals;

- iv. 2010 Actuals exceeding 2009 Actuals;
 - v. 2011 Actuals exceeding 2010 Actuals;
 - vi. 2012 Estimated Actuals exceeding 2011 Actuals; and
 - vii. 2013 Elements of Revenue Requirement exceeding 2012 Estimated Actuals.
- c) For each of the line item explanations in each year provided in response to the previous question, please identify the portion of each line item that represents an efficiency or productivity gain compared to the previous year and whether that productivity or efficiency gain continues into the following year;
- d) For each of the line item explanations in each year to be provided above, please identify items of gain that were neither efficiency nor productivity gains, and describe the factors that gave rise to savings that were neither productivity nor efficiency related such as the following:
- i. An initial under-forecast of revenues; and/or
 - ii. An initial over-forecast of expenses.

Response:

- a) During the preparation of this response Union determined that the adjusted revenue deficiency/(sufficiency) for the years 2010 through 2012 were calculated in error. The affected schedules are: Exhibit F3, Tab 1, Schedule 1; Exhibit F4, Tab 1, Schedule 1; Exhibit F5, Tab 1, Schedule 1; and Exhibit F6, Tab 1, Schedule 1.

When calculating the adjusted revenue deficiency/(sufficiency), Union did not remove the ratepayer portion of the transactional S&T margin.

Please see Attachment 1.

- b) Please see Attachment 2 for the requested analysis. Explanations below are relative to the overall deficiency estimated for 2013. Positive numbers on the analysis equate to an increase in the deficiency while negative numbers equate to a decrease in the deficiency.

For O&M variance explanations for (i) to (iv) see response to J.D-1-5-7. For O&M variance explanations for (v) to (vi) see pre-filed evidence Exhibit D5, Tab 3, Schedule 2 pp. 2 to 8 and Exhibit D4, Tab 3, Schedule 2, pages 2 to 8. For (vii) please see Attachment 3 which has revised explanations for Exhibit D3, Tab 3, Schedule 2, pp. 2 to 8.

(i) 2007 vs. 2007 BA

Contract Market

The decrease to the deficiency is largely due to the Power (Lennox) and Steel/Chemical/Refinery markets offset partially by the Wholesale market.

General Service Market

The increase to the deficiency is due to warmer than normal weather and lower customer growth than expected, offset partially by favourable usage.

S&T

The decrease to the deficiency is due mainly to higher short-term transportation revenue.

Other Revenue

The decrease to the deficiency is due to account opening charges, mid-market transactions and other operating revenues. Please refer to J.C-5-5-4 for further information.

Delivery-related Gas Costs

The increase to the deficiency is due to higher unaccounted for gas partially offset by favourable winter peaking service and compressor fuel expense.

Other Expense

n/a

Rate Base Growth net of Tax Changes & Debt Costs

The decrease to the deficiency is a result of a decreased return component due to lower rate base, lower debt costs and lower depreciation and property tax.

ROE Formula Change

n/a

Capital Structure Change

n/a

(ii) 2008 vs. 2007

Contract Market

The increase to the deficiency is due to decreases in the Large Commercial/Industrial Key market partially offset by revenue growth in the Greenhouse market mainly as a result of cold weather.

General Service Market

The decrease to the deficiency is due to colder weather, customer growth and reduction of the storage subsidies offset partially by lower usage.

S&T

The decrease to the deficiency is mainly due to: a) new long-term transportation contracts entered into during 2008 as compared to 2007, due largely to additional Dawn-Parkway capacity as a result of TFEP; b) higher exchange revenue as a result of Union's asset optimization strategy which utilized additional capacity and TCPL FT RAM credits; c) higher short-term transportation revenue; and d) the elimination of the deferral accounts for transmission-related transactional services. These were partially offset by a M12 rate decrease and decreases to the long-term peak storage margin sharing.

Other Revenue

The increase to the deficiency is due to the favourable items in 2007 reversing in 2008 for mid-market transactions and other operating revenue.

Delivery-related Gas Costs

The decrease to the deficiency is due to lower unaccounted for gas and intra-period WACOG.

Other Expense

n/a

Rate Base Growth net of Tax Changes & Debt Costs

The increase to the deficiency is due to a higher return component, depreciation and property tax related to a rate base increase of \$145 million, offset by lower debt costs and lower income taxes due to a rate decrease and timing differences.

ROE Formula Change

The increase to the deficiency is due to an increase in the benchmark return by 27 bps.

Capital Structure Change
n/a

(iii) 2009 vs. 2008

Contract Market

The increase to the deficiency is due to lower revenue within the Large Commercial/Industrial market as a result of the recession partially offset by revenue increases due to Clean Energy Supply projects in the Power market.

General Service Market

The decrease to the deficiency is due to favourable usage and reduction of the long-term peak storage margin sharing offset by warmer weather and customer growth.

S&T

The decrease to the deficiency is due to: a) increased capacity sold as a result of the Parkway expansion in November 2008; b) and higher exchange revenue as a result of increased optimization and use of TCPL FT RAM credits, offset partially by a decrease to the long-term peak storage margin sharing.

Other Revenue
n/a

Delivery-related Gas Costs

The increase to the deficiency is due to higher winter peaking service costs and intra-period WACOG.

Other Expense

The increase to the deficiency is due to a write-off of asset pre-spend and foreign exchange losses.

Rate Base Growth net of Tax Changes & Debt Costs

The increase to the deficiency is due to higher return component, depreciation and property tax related to a rate base increase of \$135 million as well as higher income taxes as a result of the reversal of timing differences offset partially by lower debt costs.

ROE Formula Change

The decrease to the deficiency is due to a decrease in the benchmark return by 34 bps.

Capital Structure Change

n/a

(iv) 2010 vs. 2009

Contract Market

The increase to the deficiency is due to decreases in revenue within the Large Commercial/Industrial market partially offset by revenue increases due to Clean Energy Supply projects in the Power market.

General Service Market

The increase to the deficiency is due to warmer weather partially offset by customer growth and reduction of the long-term peak storage margin sharing.

S&T

The increase to the deficiency is due to a decrease in the long-term storage subsidy offset by new contracts and higher short-term transportation revenue.

Other Revenue

The increase to the deficiency is due to lower delayed payment charges and a decrease in billing revenues as a result of general service customer migration from direct purchase to system sales service. This was partially offset by an increase in other operating revenue.

Delivery-related Gas Costs

The decrease to the deficiency is due to lower unaccounted for gas.

Other Expense

The decrease to the deficiency is due to lower foreign exchange losses and an absence of asset write-offs.

Rate Base Growth net of Tax Changes & Debt Costs

The decrease to the deficiency is due to lower debt costs and lower income taxes due to a rate decrease offset by a higher return component, depreciation and property tax related to a rate base increase of \$87 million.

ROE Formula Change

The increase to the deficiency is due to an increase in the benchmark return by 7 bps.

Capital Structure Change
n/a

(v)2011 vs. 2010

Contract Market
n/a

General Service Market

The decrease to the deficiency is due to favourable weather, customer growth and reduction of the long-term peak storage margin sharing.

S&T

The decrease to the deficiency is due primarily to higher exchanges revenue offset partially by a decrease to the long-term peak storage margin sharing.

Other Revenue
n/a

Delivery-related Gas Costs

The decrease to the deficiency is due to lower unaccounted for gas expense.

Other Expense

The increase to the deficiency is due to a gain on sale of assets and foreign exchange gains.

Rate Base Growth net of Tax Changes & Debt Costs

The deficiency is unchanged due to the increase return component and depreciation related to a rate base increase of \$13 million being offset by lower debt costs and lower income taxes due to a rate decrease.

ROE Formula Change

The decrease to the deficiency is due to a decrease in the benchmark return by 44 bps.

Capital Structure Change

n/a

(vi) 2012 vs. 2011

Contract Market

The increase to the deficiency is due to forecasted declines in revenues within the Large Commercial/Industrial, Power and Steel/Chemical/Refinery markets.

General Service Market

The decrease to the deficiency is due to estimated customer growth partially offset by the Dawn Gateway cancellation not recurring in 2012.

S&T

The increase to the deficiency is due primarily to reduced exchanges revenue as a result of the expected elimination of TCPL FT RAM credits in November, 2012, and the expected downward pressure on market spreads for exchange paths as a result of the increase in shale production. Long-term transportation is expected to be negatively impacted by capacity turnback, however this is partially offset by forecasted new sales.

Other Revenue

n/a

Delivery-related Gas Costs

The increase to the deficiency is due to estimated higher unaccounted for gas and compressor fuel expenses.

Other Expense

The increase to the deficiency is due to 2011 transactions not expected to recur in 2012.

Rate Base Growth net of Tax Changes & Debt Costs

The increase to the deficiency is due to a higher return component, depreciation and property tax related to an estimated rate base increase of \$100 million, offset by lower debt costs and lower income taxes due to a rate decrease.

ROE Formula Change

No change.

Capital Structure Change

n/a

(vii) 2013 vs. 2012

Contract Market

The increase to the deficiency is due to forecasted declines in revenues within the Large Commercial/Industrial and Steel/Chemical/Refinery markets.

General Service Market

The increase to the deficiency is due to fully implementing the 20 year weather trend methodology in the forecast and lower usage offset partially by estimated customer growth.

S&T

The increase to the deficiency is due to capacity turnback negatively affecting long-term transportation, reductions in exchanges revenue due to the full year impact of the expected elimination of TCPL FT RAM credits in November, 2012, expected continued downward pressure on market spreads for exchange paths as a result of the increase in shale production and an estimated reduction to the storage subsidy.

Other Revenue

n/a

Delivery-related Gas Costs

The deficiency is expected to increase due to an estimated increase in compressor fuel expense offset partially by an estimated lower unaccounted for gas expense.

Other Expense

n/a

Rate Base Growth net of Tax Changes & Debt Costs

The decrease to the deficiency is due to revised depreciation as per the study completed for 2013, lower debt costs and lower incomes taxes due to a rate decrease offset partially by a higher return component related to an estimated rate base increase of \$59 million.

ROE Formula Change

The increase to the deficiency is due to a projected increase in the allowed return on equity by 148 bps.

Capital Structure Change

The decrease to the deficiency is due to the proposal to increase the common equity component from 36% to 40%. See Exhibit E1, Tab 1.

- c) Productivity savings initiatives are not categorized at the level of detail requested. Please see the response at Exhibit J.O-4-1-9 for Total Cost Savings and Incremental Revenue Generation for years 2008 through 2012.
- d) Please see the response to b) above.

UNION GAS LIMITED
Financial Summary including Derivation of Revenue Deficiency/Sufficiency

Line No.	Particulars	2007 EB-2005-0520 Approved (a)	2007 Actual (b)	2008 Actual (c)	2009 Actual (d)	2010 Actual (e)	2011 Actual (f)	2012 Estimate (g)	2013 EB-2011-0210 Proposed (h)
	Operating Revenues: (\$'000s)								
1	Gas Sales	1,796,757	1,811,101	1,865,629	1,699,503	1,497,451	1,482,738	1,437,998	1,401,869
2	Transportation	127,701	132,925	165,085	177,325	183,331	193,605	180,668	162,055
3	Storage	17,962	24,261	23,327	28,914	20,887	10,964	9,090	11,488
4	Other	24,434	29,849	26,288	26,713	23,504	23,080	23,162	23,132
5	Earnings sharing								
6	Total Operating Revenue	1,966,854	1,998,136	2,080,329	1,932,455	1,723,173	1,710,387	1,650,918	1,598,544
	Operating Expenses: (\$'000s)								
7	Cost of gas	1,135,825	1,154,203	1,169,446	1,023,220	795,549	755,941	721,228	697,838
8	Operating and maintenance expenses	326,222	320,302	324,832	320,325	351,634	371,731	383,774	393,228
9	Depreciation	173,780	168,465	180,253	187,173	190,176	195,477	204,145	196,467
10	Other financing	315	636	535	474	621	343	362	1,179
11	Property and capital taxes	67,709	64,476	64,942	66,638	65,130	60,700	62,916	64,022
12	Income taxes	14,589	28,436	36,277	36,288	30,214	33,119	18,560	6,574
13	Other expense(income)				3,050	500	(709)		
14	Return	259,490	251,931	257,617	260,189	260,839	251,384	255,643	291,851
15	Total Cost of Service including Return	1,977,930	1,988,449	2,033,902	1,897,357	1,694,663	1,667,986	1,646,627	1,651,159
16	Revenue Deficiency/(Sufficiency) after tax	11,076	(9,687)	(46,427)	(35,098)	(30,510)	(42,401)	(4,291)	52,615
17	Provision for income taxes on deficiency (sufficiency)	6,263	(5,477)	(23,388)	(17,287)	(13,707)	(16,694)	(1,527)	18,009
18	Total revenue deficiency/(sufficiency)	17,339	(15,164)	(69,815)	(52,385)	(44,217)	(59,095)	(5,818)	70,625
19	Remove net short-term storage revenue	15,829	17,630	14,858	22,789	16,753	7,900	5,109	7,535
20	Remove net transportation revenue	3,436	9,748						
21	Long-term storage premium subsidy	(19,265)	(19,265)	(16,053)	(10,702)	(5,351)			
22	Short-term storage premium subsidy	(14,246)	(14,246)	(11,254)	(11,254)	(11,254)	(11,254)	(11,254)	(6,782)
23	Transportation premium subsidy	(3,093)	(3,093)						
24	Adjusted revenue deficiency/(sufficiency)	-	(24,390)	(82,264)	(51,552)	(44,069)	(62,449)	(11,963)	71,378

UNION GAS LIMITED
Financial Summary including Derivation of Revenue Deficiency/Sufficiency

Line No.	Particulars	2007 EB-2005-0520 Approved (a)	2007 Actual (b)	2008 Actual (c)	2009 Actual (d)	2010 Actual (e)	2011 Actual (f)	2012 Estimate (g)	2013 EB-2011-0210 Proposed (h)
Operating Revenues: (\$000s)									
1	Gas Sales	1,796,757	1,811,101	1,865,629	1,699,503	1,497,451	1,482,738	1,437,998	1,401,869
2	Transportation	127,701	132,925	165,085	177,325	183,331	193,605	180,668	162,055
3	Storage	17,962	24,261	23,327	28,914	20,887	10,964	9,090	11,488
4	Other	24,434	29,849	26,288	26,713	23,504	23,080	23,162	23,132
5	Earnings sharing	-	-	-	-	-	-	-	-
6	Total Operating Revenue	1,966,854	1,998,136	2,080,329	1,932,455	1,725,173	1,710,387	1,650,918	1,598,544
Operating Expenses: (\$000s)									
7	Cost of gas	1,135,825	1,154,203	1,169,446	1,023,220	795,549	755,941	721,228	697,838
8	Operating and maintenance expenses	326,222	320,302	324,832	320,325	351,634	371,731	383,774	393,228
9	Depreciation	173,780	168,465	180,253	187,173	190,176	195,477	204,145	196,467
10	Other financing	315	636	535	474	621	343	362	1,179
11	Property and capital taxes	67,709	64,476	64,942	66,638	65,130	60,700	62,916	64,022
12	Income taxes	14,589	28,436	36,277	36,288	30,214	33,119	18,560	6,574
13	Other expense(income)	-	-	-	3,050	500	(709)	-	-
14	Return	259,490	251,931	257,617	260,189	260,839	251,384	255,643	291,851
15	Total Cost of Service including Return	1,977,930	1,988,449	2,033,902	1,897,357	1,694,663	1,667,986	1,646,627	1,651,159
16	Revenue Deficiency/(Sufficiency) after tax	11,076	(9,687)	(46,427)	(35,098)	(30,510)	(42,401)	(4,291)	52,615
17	Provision for income taxes on deficiency (sufficiency)	6,263	(5,477)	(23,388)	(17,287)	(13,707)	(16,694)	(1,527)	18,009
18	Total revenue deficiency/(sufficiency)	17,339	(15,164)	(69,815)	(52,385)	(44,217)	(59,095)	(5,818)	70,625
19	Remove net short-term storage revenue	15,829	17,630	14,858	22,789	16,753	7,900	5,109	7,535
20	Remove net transportation revenue	3,436	9,748	-	-	-	-	-	-
21	Long-term storage premium subsidy	(19,265)	(19,265)	(16,053)	(10,702)	(5,351)	-	-	-
22	Short-term storage premium subsidy	(14,246)	(14,246)	(11,254)	(11,254)	(11,254)	(11,254)	(11,254)	(6,782)
23	Transportation premium subsidy	(3,093)	(3,093)	-	-	-	-	-	-
24	Adjusted revenue deficiency/(sufficiency)	-	(24,390)	(82,264)	(51,552)	(44,069)	(62,449)	(11,963)	71,378

UNION GAS LIMITED
Revenue Deficiency/Sufficiency Components

Line. No.	Particulars (\$ millions)	2007 BA vs 2013 (a)	2007 BA vs 2007 (b)	2007 vs 2008 (c)	2008 vs 2009 (d)	2009 vs 2010 (e)	2010 vs 2011 (f)	2011 vs 2012 (g)	2012 vs 2013 (h)
	Revenue:								
1	Contract Market	7	(11)	2	4	2	-	8	2
2	General Service Market	(13)	6	(16)	(1)	11	(17)	(2)	6
3	S&T ⁽¹⁾	(10)	(3)	(34)	(5)	1	(4)	11	24
4	Other Revenue	1	(5)	3	-	3	-	-	-
5	Sub Total: Net Revenue	(15)	(13)	(45)	(2)	17	(21)	17	32
6	Delivery-related Gas Costs:	(37)	9	(25)	17	(39)	(8)	4	5
	O&M:								
7	Compensation	59	5	3	4	26	19	(3)	5
8	Contract Services	23	2	5		2	6	3	5
9	DSM Programs	12			2	2	1	6	1
10	Outbound Affiliates	(8)	(1)		(2)	(1)	(2)	(2)	
11	Bad Debt	(5)	(4)	2		(4)	(1)	2	
12	Capitalization	(14)	4	(7)	2	(1)	(7)	(2)	(3)
13	Non-Utility Allocations	(7)		(3)	(4)	1	(1)		
14	Other	7	(12)	4	(6)	7	5	8	1
15	Sub Total: Net O&M	67	(6)	4	(4)	32	20	12	9
16	Other Expense				3	(3)	(1)	1	
17	Rate Base Growth Net of Tax Changes & Debt Costs	20	(14)	3	23	(1)	-	16	(7)
18	ROE Formula Change	19		5	(6)	1	(8)	-	27
19	Capital Structure Change	17							17
20	Revenue Deficiency/(sufficiency)	71	(24)	(58)	31	7	(18)	50	83

Note:

(1) Adjusted for the storage premium embedded in rates.

(2) Calculated using 36% of the latter year rate base and grossed up using the latter

UNION GAS LIMITED

Operating and Maintenance Expense by Cost Type

2013 Forecast vs. 2012 Forecast

Line No.	Notes:	(\$000's)
	<u>Salaries / Wages</u>	
1	2013 Forecast	193,787
2	2012 Forecast	187,950
3	Difference	<u>5,837</u>
	Reasons:	
4	Merit increase	6,900
5	Market Development - Energy Technology and Innovation Canada	100
6	Other	<u>(1,163)</u>
7	Total difference: 2013 Forecast vs. 2012 Forecast	<u>5,837</u>
	<u>Benefits</u>	
8	2013 Forecast	81,083
9	2012 Forecast	82,161
10	Difference	<u>(1,078)</u>
	Reasons:	
11	Increased non pension benefit costs	1,441
12	Decreased pension benefit costs	<u>(2,519)</u>
13	Total difference: 2013 Forecast vs. 2012 Forecast	<u>(1,078)</u>
	<u>Materials</u>	
14	2013 Forecast	9,958
15	2012 Forecast	9,242
16	Difference	<u>716</u>
	Reasons:	
17	Other	<u>716</u>
18	Total difference: 2013 Forecast vs. 2012 Forecast	<u>716</u>

UNION GAS LIMITED
 Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	(\$000's)
	<u>Employee Expenses / Training</u>	
1	2013 Forecast	14,330
2	2012 Forecast	14,110
3	Difference	<u>220</u>
	Reasons:	
4	Travel	83
5	Training	125
6	Other	12
7	Total difference: 2013 Forecast vs. 2012 Forecast	<u>220</u>
	<u>Contract Services</u>	
8	2013 Forecast	66,376
9	2012 Forecast	63,670
10	Difference	<u>2,706</u>
	Reasons:	
11	Pipeline integrity	900
12	Line locates	583
13	Banner transactional fee	300
14	Other	923
15	Total difference: 2013 Forecast vs. 2012 Forecast	<u>2,706</u>
	<u>Consulting</u>	
16	2013 Forecast	13,172
17	2012 Forecast	11,082
18	Difference	<u>2,090</u>
	Reasons:	
19	Market Development - Energy Technology and Innovation Canada	2,010
20	Other	80
21	Total difference: 2013 Forecast vs. 2012 Forecast	<u>2,090</u>

UNION GAS LIMITED
 Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	(\$000's)
	<u>General</u>	
1	2013 Forecast	22,190
2	2012 Forecast	21,592
3	Difference	598
	Reasons:	
4	Other	598
5	Total difference: 2013 Forecast vs. 2012 Forecast	598
	<u>Transportation and Maintenance</u>	
6	2013 Forecast	9,761
7	2012 Forecast	9,375
8	Difference	386
	Reasons:	
9	Volume and price	386
10	Total difference: 2013 Forecast vs. 2012 Forecast	386
	<u>Company Used Gas</u>	
11	2013 Forecast	2,501
12	2012 Forecast	2,473
13	Difference	28
	Reasons:	
14	Volume and price	28
15	Total difference: 2013 Forecast vs. 2012 Forecast	28
	<u>Utility Costs</u>	
16	2013 Forecast	4,682
17	2012 Forecast	4,562
18	Difference	120
	Reasons:	
19	Increased utility costs	120
20	Total difference: 2013 Forecast vs. 2012 Forecast	120

UNION GAS LIMITED
 Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	(\$000's)
	<u>Communications</u>	
1	2013 Forecast	6,380
2	2012 Forecast	6,243
3	Difference	137
	Reasons:	
4	Other	137
5	Total difference: 2013 Forecast vs. 2012 Forecast	137
	<u>Demand Side Management Programs</u>	
6	2013 Forecast	24,232
7	2012 Forecast	23,605
8	Difference	627
	Reasons:	
9	DSM program costs	627
10	Total difference: 2013 Forecast vs. 2012 Forecast	627
	<u>Advertising</u>	
11	2013 Forecast	2,386
12	2012 Forecast	2,288
13	Difference	98
	Reasons:	
14	Other	98
15	Total difference: 2013 Forecast vs. 2012 Forecast	98
	<u>Insurance</u>	
16	2013 Forecast	9,056
17	2012 Forecast	8,605
18	Difference	451
	Reasons:	
19	Higher insurance premiums	451
20	Total difference: 2013 Forecast vs. 2012 Forecast	451

UNION GAS LIMITED
 Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	(\$000's)
	<u>Donations</u>	
1	2013 Forecast	788
2	2012 Forecast	775
3	Difference	<u>13</u>
	<u>Reasons:</u>	
4	Other	<u>13</u>
5	Total difference: 2013 Forecast vs. 2012 Forecast	<u>13</u>
	<u>Financial</u>	
6	2013 Forecast	1,871
7	2012 Forecast	1,860
8	Difference	<u>11</u>
	<u>Reasons:</u>	
9	Other	<u>11</u>
10	Total difference: 2013 Forecast vs. 2012 Forecast	<u>11</u>
	<u>Lease</u>	
11	2013 Forecast	4,191
12	2012 Forecast	4,151
13	Difference	<u>40</u>
	<u>Reasons:</u>	
14	Other	<u>40</u>
15	Total difference: 2013 Forecast vs. 2012 Forecast	<u>40</u>
	<u>Cost Recovery from Third Parties</u>	
16	2013 Forecast	(2,549)
17	2012 Forecast	(2,883)
18	Difference	<u>334</u>
	<u>Reasons:</u>	
19	Other	<u>334</u>
20	Total difference: 2013 Forecast vs. 2012 Forecast	<u>334</u>

UNION GAS LIMITED
 Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	(\$000's)
	<u>Computers</u>	
1	2013 Forecast	6,465
2	2012 Forecast	6,158
3	Difference	<u>307</u>
	Reasons:	
4	Other	<u>307</u>
5	Total difference: 2013 Forecast vs. 2012 Forecast	<u>307</u>
	<u>Regulatory Hearing & OEB Cost Assessment</u>	
6	2013 Forecast	4,300
7	2012 Forecast	5,200
8	Difference	<u>(900)</u>
	Reasons:	
9	Rebasing	<u>(900)</u>
10	Total difference: 2013 Forecast vs. 2012 Forecast	<u>(900)</u>
	<u>Outbound Affiliate Services</u>	
11	2013 Forecast	(13,706)
12	2012 Forecast	(13,667)
13	Difference	<u>(39)</u>
	Reasons:	
14	Other	<u>(39)</u>
15	Total difference: 2013 Forecast vs. 2012 Forecast	<u>(39)</u>
	<u>Inbound Affiliate Services</u>	
16	2013 Forecast	11,888
17	2012 Forecast	11,494
18	Difference	<u>394</u>
	Reasons:	
19	Other	<u>394</u>
20	Total difference: 2013 Forecast vs. 2012 Forecast	<u>394</u>

UNION GAS LIMITED
 Operating and Maintenance Expense by Cost Type
2013 Forecast vs. 2012 Forecast

Line No.	Notes:	(\$000's)
	<u>Bad Debt</u>	
1	2013 Forecast	6,600
2	2012 Forecast	6,600
3	Difference	-
4	Total difference: 2013 Forecast vs. 2012 Forecast	-
	<u>Other</u>	
5	2013 Forecast	139
6	2012 Forecast	141
7	Difference	(2)
	Reasons:	
8	Other	(2)
9	Total difference: 2013 Forecast vs. 2012 Forecast	(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 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
(10⁶ m³)

<u>Market Sector</u>	<u>Board- approved 2007</u>	<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Actual</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>	<u>Forecast</u>
		<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>Forecast</u>	<u>Volume</u>	<u>Volume</u>	<u>Customer #</u>	<u>Customer #</u>
										<u>Not</u>	<u>MFG</u>	<u>Not MFG</u>	<u>MFG</u>
1 Power	1,831	2,078	1,659	1,854	2,349	2,464	2,215	2,189	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	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	2,117	522	1,596	109	227
4 Greenhouse	146	173	203	197	246	287	303	315	315	315	0	101	0
5 Wholesale/REM	346	297	305	319	315	324	330	334	334	334	0	6	0
6 Totals ⁽¹⁾	8,521	8,625	8,386	7,560	8,344	8,837	8,824	8,689	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
 (10⁶m³)

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
	Other												
8	(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

Undertaking of Mr. Thompson
To Ms. Van Der Paelt

Please provide number of M1 and M2 customers that are manufacturers.

Manufacturers by General Service Rate Class
from Billing System Enquiry June 1 2012

Union South	Rate M1	6,718
	Rate M2	<u>1,505</u>
	Sub-Total	<u>8,223</u>
Union North	Rate 01	1,150
	Rate 10	<u>247</u>
	Sub-Total	<u>1,397</u>
All General Service Rates Classes		<u><u>9,620</u></u>

UNION GAS LIMITED

Undertaking of Mr. Thompson
To Mr. Shorts

3. [J.C-3-14-1 Attachment 3] This exhibit indicates that there are 261 customers in various rate classes that Union classifies as manufacturers. This exhibit does not refer to either M2 or Rate 10 customers. By way of clarification, are there any customers served under the auspices of Rate M2 and Rate 10 that Union would classify as manufacturers? If so, please provide the number of such customers in each rate class.

By cross-referencing the information in this exhibit pertaining to the number of manufacturers served by Union and the rate impact information shown in Exhibits J.F-2- 5-1 and J.H-1-14-2, please indicate the number of manufacturers being served by Union in each rate class who will be facing a rate increase greater than 2% if all of the relief requested by Union in this application is approved.
customers of the rate impacts?

10. Revenue Requirement

[J.F-2-5-1] Slides 5 and 6 in this presentation to Union's Board of Directors contained rate impact information. Please modify those slides to show the rate impacts in a scenario where the revenue deficiency for 2013 is zero. We are interested in obtaining a presentation of this nature that will separate the impact of the cost allocation and rate design changes Union is proposing from the revenue deficiency amount being requested for 2013.

11. H. Rate Design

[J.H-1-14-2] Is the information presented in this interrogatory response compatible with the impacts that were presented to Union's Directors in Exhibit J.F-2-5-1? If not, then please revise the impacts presented to Union's Directors in Exhibit J.F-2-5-1 to reflect the information contained in this exhibit.

Also, please provide a status report on the presentations to the T1 customers of the rate impacts?

-
3. Please see the response at Exhibit JT1.16 for the number of M1 and M2 customers that are manufacturers.

Based on Union's 2013 proposed delivery rates, Union estimates that all 9,620 manufacturers identified in Rate M1, Rate M2, Rate 01 and Rate 10 will face a delivery rate increase of greater than 2%.

10. Union's response is at p. 166 of the June 1, 2012 transcript.

11. Please see Attachment 1 for the updated slides.

Union has provided additional information to existing T1 customers about the proposed T1 and T2 rate proposal at customer meeting's in London and Burlington in the May/June 2012 timeframe. Please see Attachment 2 for the presentation made at the London meeting in June.

Annual Bill Impacts – General Service

General Service Rate Class	Total Bill Impact	Total Bill Impact
<u>Union North</u>		
Small Volume Rate 01 (@ 2,200 m ³ /yr)	\$ 59 - \$ 76	7 % – 9 %
Large Volume Rate 10 (@ 93,000 m ³ /yr)	\$ 296 – \$ 1,026	1 % – 4 %
<u>Union South</u>		
Small Volume Rate M1 (@ 2,200 m ³ /yr)	\$ 19	3 %
Large Volume Rate M2 (@ 73,000 m ³ /yr)	\$ 446	3 %

Average Delivery Rate Impacts – Contract Rate Classes



Rate Class	Rate Change (cents/m ³)	Rate Change (\$/GJ)	Delivery Bill Impact (%)
M4	0.5563	0.147	20
M5A	0.6941	0.184	42
M7	0.1295	0.034	5
M9	(0.0551)	(0.015)	(4)
M10	0.4527	0.120	18
T1 – Small	0.4116	0.109	33
T1 – Average	0.2738	0.072	19
T1 – Large	(0.1206)	(0.032)	(19)
T3	0.0599	0.016	4
Rate 20	0.6734	0.178	43
Rate 25	0.7826	0.207	43
Rate 100	0.1941	0.051	29



2013 Cost of Service Filing EB-2011-0210

Agenda

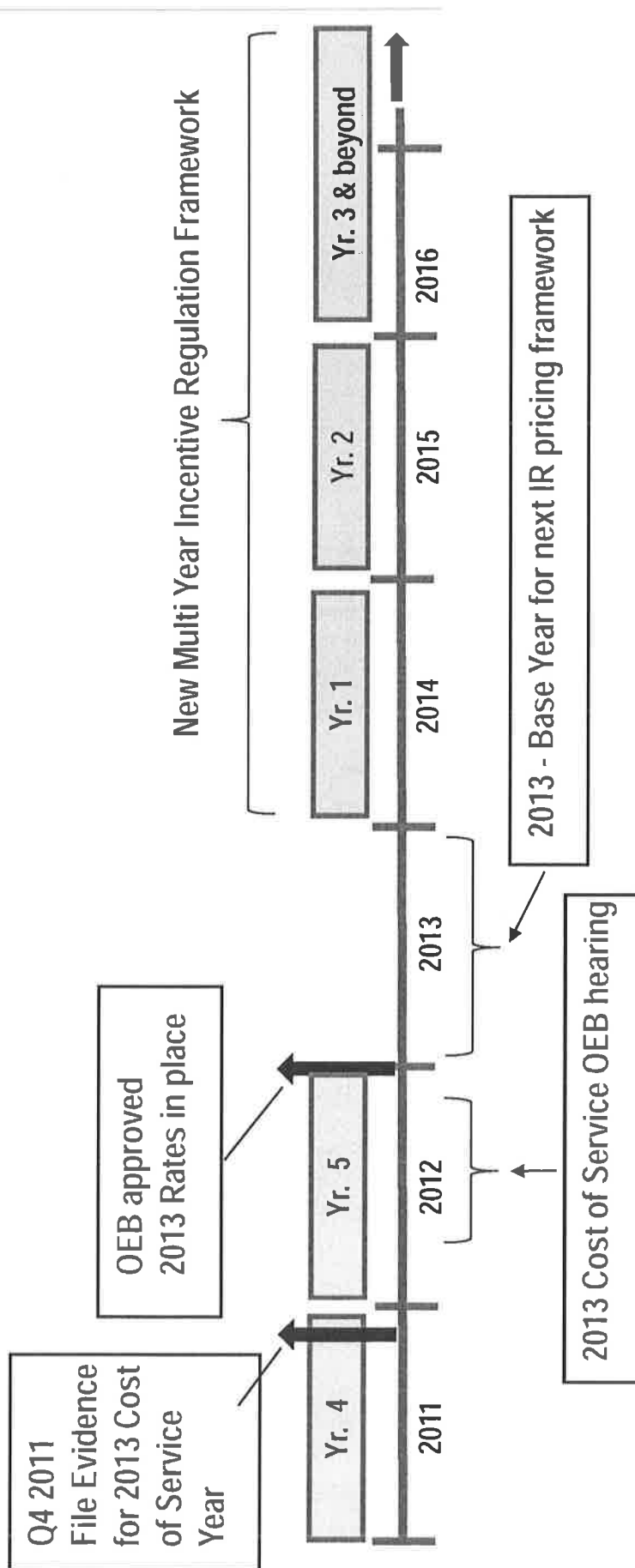


2013 Cost of Service Filing

Rate Design Proposals

- Bundled Contract Rate Eligibility (M4, M5A, M7)
- Rate T1 Redesign
 - Proposed New Rate T1 and Rate T2
- Elimination of Contract Rate Unbundled Service Offerings

Looking Forward...



Key Messages



- 2013 Cost of Service establishes new baseline for Board approved rates
- 2013 Contract Rate Class volume forecast recognizes impacts of global trends
 - Demand destruction (plant closures, energy efficiency)
 - Global competition (higher CDN \$, international ownership)

Rate Review Guidelines



Key Guidelines for appropriate rate design:

- Common profiles within rate classes
- Sufficient rate class size
- Sufficient differentiation among rate groupings
- Sufficient interest and reasonable prospect of use
- Rate harmonization

Contract Service – Bundled



Proposed M4, M5A and M7 Eligibility Changes

Contract Service – Bundled For Rates M4 and M5A



Rate Design Changes	Current Approved	Proposed
Lower Union South bundled mid-market rate class eligibility	Daily Contract Demand of 4,800 to 140,870 m³/d	Daily Contract Demand of 2,400 to 60,000 m³/d
	Minimum Annual Volume of 700,000 m³	Minimum Annual Volume of 350,000 m³
	Rate M4 load factor of at least 40%	Rate M4 load factor of at least 40%
For Rate M4 Only	Firm Contract Demand only	Firm Contract Demand with Interruptible Option

Proposed Implementation: January 1, 2014

Contract Service – Bundled For Rate M7



Rate Design Changes	Current Approved	Proposed
Lower Union South bundled large volume rate class eligibility	Combined Firm, Interruptible and Seasonal CD of at least 140,870 m³/d	Combined Contract Demand of at least 60,000 m³/d
	Annual Volume of at least 28,327,840 m³	No MAV required for eligibility

Proposed Implementation: January 1, 2014

Proposed Rate T1 Re-design

Proposed Rate T1



Rate Design Changes	Current Approved T1	Proposed T1
Split Current T1 Class into T1 and T2 rate classes	5,000,000 m³ Qualifying Annual Volume	2,500,000 m³ Qualifying Annual Volume - Firm Contract Demand up to 140,870 m³/d
	- Two Firm Contract Demand Blocks - First 140,870 m³/d - All Over 140,870 m³/d	- Two Firm Contract Demand Blocks - First 28,150 m³/d - Next 112,720 m³/d
	- Two Firm Commodity blocks - First 2,360,653 m³ - All Over 2,360,653 m³	Single Firm Commodity rate
Monthly Customer charge per delivery point	\$1,795.31	\$1,998.83

Proposed Rate T2



Rate Design Changes	Current Approved T1	Proposed T2
Split Current T1 Class into T1 and T2 rate classes	5,000,000 m³ Qualifying Annual Volume	Firm daily Contract Demand of at least 140,870 m³/d
	- Two Firm Contract Demand Blocks - First 140,870 m³/d - All Over 140,870 m³/d	- Two Firm Contract Demand Blocks - First 140,870 m³/d - All Over 140,870 m³/d
	- Two Firm Commodity blocks - First 2,360,653 m³ - All Over 2,360,653 m³	Single Firm Commodity rate
Monthly Customer charge per delivery point	\$1,795.31	\$6,000

Proposed Implementation: January 1, 2013

Elimination of Contract Rate Unbundled Service Offerings



- Union South – Rates U5, U7 and U9
- Union North – Rate 20 and Rate 100 Unbundled Services
- Rate schedules have been available for over ten years with no customers contracting for the services
- No customers forecasted in 2013 to utilize these services

Proposed Elimination: January 1, 2013

Questions

UNION GAS LIMITED

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

Please provide copies of all materials provided to Union's Board of Directors when it sought Board approval of the 2013 revenue requirement. When was approval of the currently filed application (including updates) granted by Union's Board of Directors?

Response:

Please see Attachment 1 for the presentation to Union's Board of Directors.

There was no Board of Directors' approval, nor any requirement for Board of Directors' approval, for Union's 2013 rate application. As stated at Section 13 of the EB-2007-0606 settlement agreement, "Union agrees (subject to any subsequent agreement of all parties to the contrary) to provide a full cost of service filing (Phase I & II) at the time of rebasing, regardless of whether Union applies to set rates for 2013 on a cost of service basis or not".



Filed: 2012-05-04

EB-2011-0210

J.F-2-5-1

Attachment 1

2013 Rebasing Proceeding

Board of Directors
Presentation
March 21, 2012

- 2013 revenue deficiency is \$75 million (approx. 9% increase before cost allocation and rate design)
- Compared to 2007 Board-approved levels, key drivers of 2013 revenue deficiency are:
 - Operating Revenue - \$61 million increase (with no rate increases)
 - Operating costs - \$81 million increase (due to increased salaries and benefits)
 - Depreciation - \$23 million increase (due to additional investment in property, plant and equipment offset by lower depreciation rates)
 - Cost of Capital - \$32 million increase (due to higher rate base, higher ROE as per the OEB's formula and proposed common equity increase from 36% to 40%)

- Key issues for the proceeding are:
 - Past financial performance
 - Request for rate increase
 - Limited growth and cost increases
 - Weather normalization methodology
 - Changes in North American natural gas supply dynamics and significant uncertainty around Dawn-Parkway demands
 - Increase in common equity component of capital structure from 36% to 40%
 - Use of new ROE formula
 - Cost allocation updates and rate redesign proposals

Dawn-Parkway Uncertainty



- Union's single biggest issue for 2013 rebasing and the next incentive regulation framework is uncertainty around demands and capacity requirements on the Dawn-Parkway system
 - Union continues to face risk of further turn-back beyond 2013
 - Outcome of TCPL mainline toll application will have implications for Dawn-Parkway demands
 - The capacity constraint at Maple limits Union's ability to sell excess Dawn-Parkway services
 - The potential need to expand Dawn-Parkway to meet requirements of new gas-fired power generation

Annual Bill Impacts – General Service



General Service Rate Class	Total Bill Impact	Total Bill Impact
<u>Union North</u>		
Small Volume Rate 01 (@ 2,200 m³/yr)	\$ 60 - \$ 77	7 % – 9 %
Large Volume Rate 10 (@ 93,000 m³/yr)	\$ 311 – \$ 1,042	1 % – 4 %
<u>Union South</u>		
Small Volume Rate M1 (@ 2,200 m³/yr)	\$ 16	2 %
Large Volume Rate M2 (@ 73,000 m³/yr)	\$ 414	2 %

Average Delivery Rate Impacts – Contract Rate Classes



Rate Class	Rate Change (cents/m ³)	Rate Change (\$/GJ)	Delivery Bill Impact (%)
M4	0.4768	0.126	17
M5A	0.4733	0.125	28
M7	0.1142	0.030	4
M9	(0.0153)	(0.004)	(1)
M10	0.5021	0.133	20
T1 – Small	0.4201	0.111	38
T1 – Average	0.1153	0.031	10
T1 – Large	(0.1087)	(0.029)	(10)
T3	0.1019	0.027	6
Rate 20	0.6434	0.170	42
Rate 25	0.6402	0.170	36
Rate 100	0.1086	0.029	16

Rebasing Proceeding: Next Steps



- File evidence update - March
- Issues Conference/Day - March
- Interrogatories - April
- Technical Conference - May
- Settlement Conference - June
- Hearing - July/August
- Argument/Reply - September
- OEB Decision - late Fall
- Implement Rates - January 1, 2013

- Due to uncertainty, need to consider options:
 - File next incentive regulation framework after 2013 rates decision
 - File COS application in the fall of 2013 for rates effective Jan. 1, 2015
- Factors to consider:
 - Changes in North American gas flows and implications on the Dawn-Parkway system
 - Outcome of TCPL mainline tolls application
 - Amount and timing of facilities east of Parkway
 - Ways to address incremental capital (Parkway, CIS)
 - Certainty around timing of new gas-fired power generation
 - Outcome of the 2013 rebasing application
 - OEB acceptance

UNION GAS LIMITED

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

Ref: Exhibit A1, Tab 3, Schedule 2
Exhibit H1, Tab 1

CME wishes to obtain a better understanding of the impacts of Union's proposed Rate Design changes on the manufacturers being served under the auspices of Union's rates. Union's manufacturer customers will be more specifically identified when Union provides its response to Interrogatory C3.1 herein. For the purposes of the information requests that follow, CME assumes that one or more manufacturers are currently being served under the auspices of Rates 01 and 10 in the Northern Zone and Rates M4, M5A, M7 and T1 in Union's Southern operations area. In connection with proposals that Union is making will affect customers served under the auspices of these existing rates, please provide the following information:

- a) Identify the total number of commercial and industrial customers who will receive an annual bill impact in excess of 2% as a result of moving from current Rate 01 and M1 to proposed Rates 10 and M2;
- b) Table 14 in Exhibit H1, Tab 1 indicates that the annual bill impacts on existing M1 customers that will move to proposed Rate Class M2 with annual volumes between 7,000 and 60,000 M³/year will face very significant annual bill increases. Have the customers who will be affected by Union's proposal been notified of the steep bill increases they will face if Union's proposals are approved? If so, then please provide copies of such notices and the responses from customers, if any.
- c) Please broaden Table 14 in Exhibit H1, Tab 1 to include annual volumes of 6,000 M³/year, 60,000 M³/year and 70,000 M³/year.
- d) With respect to the proposal to lower the Rate 7 eligibility to capture 5 customers currently forecast on Rate M4 at 17 customers currently on Rate M5A, please provide information that will show the rate and annual bill impacts on each of the 22 customers that will be brought within the ambit of Rate M7 under Union's proposal.
- e) What will be the impact on rates and annual bills of customers who choose to utilize Union's proposed Rate M4 interruptible service offering?
- f) With respect to Union's proposal to split current Rate T1 into two rate classes, please provide the following:
 - i. A Schedule that will show the range of rate and annual bill impacts on the 59 customers currently served under Rate T1 if Union's proposal is adopted;

- ii. Identify by letter or number each customer to be served under proposed Rate T1 and proposed Rate T2 that will be facing either a rate or a total annual bill impact increase that is 2% or greater;
- iii. Any specific notice that Union has provided to T1 customers of the rate and/or annual bill impacts that they will likely face if Union's proposed Rate Design change is approved and the responses that Union received to these notices, if any.

Response:

- a) Based on 2010 actual customer data, Union estimates the number of accounts and the financial impact on each of the four rate classes is as follows:

Union North - Rate 01 and Rate 10

- 1) 281,246 accounts with annual volume up to 5,000 m³ will see no impact at 100 m³ and an annual decrease of approximately \$2 at 5,000 m³. These existing Rate 01 accounts will continue to take service under the proposed Rate 01 in 2014.
- 2) 18,163 accounts with annual volume between 5,000 m³ and 50,000 m³ represent existing Rate 01 accounts that will take service under the proposed Rate 10 in 2014. Financial impacts are as follows:
 - i) An annual bill increase for 6,816 accounts with annual volumes between 5,000 m³ and 7,000 m³. The annual increase ranges from approximately \$43 at 5,001 m³ to \$4 at 7,000 m³.
 - ii) An annual bill decrease for 11,347 accounts with annual volumes between 7,001 m³ and 50,000 m³. The annual decrease ranges from approximately \$5 at 7,500 m³ to \$816 at 50,000 m³.
- 3) 1,735 accounts with annual volume over 50,000 m³ represent existing Rate 10 accounts that will continue to take service under the proposed Rate 10 in 2014. Financial impacts are as follows:
 - i) 1,142 accounts with annual volume between 50,000 m³ and 117,000 m³ will see an annual decrease from approximately \$266 at 50,001 m³ to approximately \$1 at 117,000 m³.
 - ii) 593 accounts with annual volume over 117,000 m³ will see an annual increase of from approximately \$14 at 120,000 m³ to approximately \$42,153 at 3,000,000 m³.

Union South - Rate M1 and Rate M2

- 1) 941,737 accounts with annual volume up to 5,000 m³ will see no impact at 100 m³ and an annual increase of up to \$2 at 5,000 m³. These existing Rate M1 accounts will continue to take service under the proposed Rate M1 in 2014.
 - 2) 50,847 accounts with annual volume between 5,000 m³ and 50,000 m³ will see an annual bill increase from approximately \$148 at 5,001 m³ to \$48 at 50,000 m³. These existing Rate M1 accounts will now take service under the proposed Rate M2 in 2014.
 - 3) 6,228 accounts with annual volume over 50,000 m³ will see an annual bill decrease from approximately \$771 at 50,001 m³ to approximately \$13,800 at 3,000,000 m³. These existing Rate M2 accounts will continue to take service under the proposed Rate M2 in 2014.
- b) No. On approval of its rate redesign proposals, Union will advise customers in anticipation of 2014 rate implementation. This approach is consistent with the implementation used in EB-2005-0520 in which Union advised customers in 2007 prior to the 2008 implementation.
- c) Please see Attachment 1.
- d) Please see Attachment 2.

Rate M5A customers will move to Rate M7 on a revenue neutral basis on the interruptible portion of their bill. There is no bill impact as the Rate M7 interruptible rate will be set to recover the same revenue calculated using the Rate M5A bill provided interruptible customers maintain the same contractual MAV commitment.

For firm Rate M4 and interruptible Rate M5A customers with an optional firm service, the firm service will be re-priced using the firm contract parameters priced at the Rate M7 firm rates.

- e) The introduction of an interruptible service offering in Rate M4 will have no impact on rates. Interruptible pricing in Rate M4 will match the rates calculated under Rate M5A, which will ensure that customers in Rate M4 and Rate M5A pay the same price for the same interruptible service.

The annual bill of customers who choose to utilize Union's proposed Rate M4 interruptible service offering will depend on the level of interruptible service elected by the customer.

For example, a current Rate M5A customer with an interruptible contracted demand of 4,800 m³ and an annual volume of 700,000 m³ has a bill, based on current approved rates, consisting of:

- a. A monthly customer charge of \$498.20
- b. A daily interruptible delivery commodity charge of 2.1435 cents/m³ for all interruptible volumes used, and
- c. An interruptible day's use discount of 0.2035 cents/m³ based on 146 days use of contracted demand.

A Rate M4 customer exercising the Rate M4 interruptible offering will pay exactly the same price as a Rate M5A customer.

- f)
 - i) Please see Attachment 3 for the annual firm transportation bill impacts related to the 2013 proposed redesign. The bill impacts have been calculated using 2013 forecast billing units and include the monthly customer charge, firm transportation demand and firm transportation commodity portions of the bill only.
 - ii) Please see Attachment 3, note (2). For proposed Rate T1, the bill impacts range from an increase of 11.3% to an increase of 39.3%. For proposed Rate T2, the bill impacts range from a decrease of 18.9% to an increase of 37.0%.
 - iii) In 2011, at customer meetings in London and Burlington, Union made preliminary presentations about some of the Rate Design proposals in its 2013 Cost of Service hearing. No additional detailed or specific information about the rate or annual bill impacts of the Rate Design changes have been shared through broad based customer communication at this time. Union historically has communicated this information at customer meetings after the evidence has been filed with the Board. Consistent with past practices Union will be presenting this information at customers meetings in 2012.

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

Annual Volume	2013 Proposed with Annual Volume Breakpoint of 50,000 m ³		2014 Proposed with Annual Volume Breakpoint of 5,000 m ³		Bill Impacts	
	Rate M1	Rate M2	Rate M1	Rate M2	\$	%
1,800	327.69		328.98		1.29	0.4%
2,200	343.16		344.58		1.42	0.4%
2,600	358.55		360.08		1.53	0.4%
3,000	373.82		375.47		1.65	0.4%
5,000	449.13		451.34		2.21	0.5%
5,001	449.17			597.10	147.93	32.9%
6,000	486.16			632.34	146.18	30.1%
7,000	523.15			667.37	144.22	27.6%
10,000	633.91			771.65	137.74	21.7%
20,000	999.67			1,117.24	117.58	11.8%
30,000	1,364.94			1,461.55	96.62	7.1%
50,000	2,095.47			2,143.84	48.37	2.3%
60,000		3,316.76		2,478.58	(838.18)	-25.3%
70,000		3,717.42		2,812.62	(904.79)	-24.3%
80,000		4,117.07		3,146.02	(971.06)	-23.6%
100,000		4,911.88		3,809.88	(1,102.00)	-22.4%
200,000		8,736.83		7,084.44	(1,652.39)	-18.9%
300,000		12,470.81		10,332.91	(2,137.89)	-17.1%
500,000		19,846.07		16,797.86	(3,048.22)	-15.4%

Notes:

(1) Grey shading represents all changes when compared to Exhibit H1, Tab 1, Updated, Table 12, page 27.

Annual Bill Impact of Rate M4 and Rate M5A customers moving to Rate M7
per Union's 2014 Rate Design Proposal

<u>Particulars (\$)</u>	2013	2014 M7	Bill Impact	
	<u>Delivery Bill</u>	<u>Delivery Bill</u>	(c) = (b-a)	(d) = (c/a)
	(a)	(b)		
<u>Rate M4</u>				
Customer 1	329,400	247,319	(82,080)	-24.9%
Customer 2	340,573	250,206	(90,367)	-26.5%
Customer 3	369,878	268,438	(101,440)	-27.4%
Customer 4	439,357	318,328	(121,029)	-27.5%
Customer 5	525,126	398,254	(126,871)	-24.2%
<u>Rate M5A</u>				
Customer 1	274,177	274,177	-	0.0%
Customer 2	98,931	98,931	-	0.0%
Customer 3	142,822	142,822	-	0.0%
Customer 4	255,200	255,200	-	0.0%
Customer 5	97,733	82,502	(15,231)	-15.6%
Customer 6	62,021	62,021	-	0.0%
Customer 7	129,731	102,642	(27,089)	-20.9%
Customer 8	220,261	220,261	-	0.0%
Customer 9	98,224	98,224	-	0.0%
Customer 10	439,276	439,276	-	0.0%
Customer 11	225,251	225,251	-	0.0%
Customer 12	215,550	215,550	-	0.0%
Customer 13	180,323	180,323	-	0.0%
Customer 14	392,773	392,773	-	0.0%
Customer 15	418,369	418,369	-	0.0%
Customer 16	630,803	630,803	-	0.0%
Customer 17	409,338	409,338	-	0.0%

Estimated Rate T1 Firm Transportation
Bill Impacts of 2013 Proposed Redesign

Particulars (\$)	Proposed Rate Class	Current Approved Firm Transportation Bill (1)	2013 Proposed Firm Transportation Bill with Redesign (1)	Annual Bill Impact (c) = (b-a)	% Change (2) (d) = (c/a)
		(a)	(b)	(c)	(d)
Customer 1	Rate T1	21,544	23,986	2,442	11.3
Customer 2	Rate T1	42,848	58,662	15,814	36.9
Customer 3	Rate T1	86,361	114,892	28,531	33.0
Customer 4	Rate T1	94,362	125,382	31,021	32.9
Customer 5	Rate T1	90,389	124,545	34,156	37.8
Customer 6	Rate T1	89,619	124,245	34,627	38.6
Customer 7	Rate T1	93,975	127,359	33,384	35.5
Customer 8	Rate T1	94,708	131,900	37,192	39.3
Customer 9	Rate T1	101,427	140,409	38,981	38.4
Customer 10	Rate T1	112,669	148,957	36,288	32.2
Customer 11	Rate T1	108,539	147,973	39,434	36.3
Customer 12	Rate T1	121,229	155,790	34,561	28.5
Customer 13	Rate T1	128,922	166,458	37,536	29.1
Customer 14	Rate T1	159,639	199,770	40,131	25.1
Customer 15	Rate T1	136,169	175,034	38,865	28.5
Customer 16	Rate T1	135,386	175,641	40,255	29.7
Customer 17	Rate T1	144,358	182,058	37,701	26.1
Customer 18	Rate T1	146,602	186,769	40,167	27.4
Customer 19	Rate T1	148,354	188,410	40,056	27.0
Customer 20	Rate T1	155,364	193,057	37,693	24.3
Customer 21	Rate T1	160,855	199,990	39,135	24.3
Customer 22	Rate T1	154,782	198,586	43,804	28.3
Customer 23	Rate T1	161,311	202,086	40,775	25.3
Customer 24	Rate T1	154,536	202,327	47,791	30.9
Customer 25	Rate T1	173,537	216,437	42,900	24.7
Customer 26	Rate T1	197,783	249,149	51,366	26.0
Customer 27	Rate T1	194,137	247,729	53,592	27.6
Customer 28	Rate T1	191,458	238,760	47,302	24.7
Customer 29	Rate T1	193,218	241,364	48,145	24.9
Customer 30	Rate T1	188,705	240,758	52,053	27.6
Customer 31	Rate T1	214,011	259,049	45,038	21.0
Customer 32	Rate T1	243,463	286,113	42,651	17.5
Customer 33	Rate T1	248,168	289,610	41,442	16.7
Customer 34	Rate T1	254,468	293,981	39,513	15.5
Customer 35	Rate T1	251,359	293,013	41,654	16.6
Customer 36	Rate T1	332,148	400,055	67,908	20.4
Customer 37	Rate T1	371,724	441,887	70,163	18.9
Customer 38	Rate T1	354,402	440,310	85,909	24.2
Customer 39	Rate T1	407,264	473,683	66,418	16.3
Customer 40	Rate T2	422,269	475,738	53,469	12.7
Customer 41	Rate T2	532,573	729,420	196,847	37.0
Customer 42	Rate T2	501,369	512,914	11,545	2.3
Customer 43	Rate T2	516,698	526,565	9,867	1.9
Customer 44	Rate T2	564,066	560,266	(3,800)	(0.7)
Customer 45	Rate T2	662,646	696,598	33,951	5.1
Customer 46	Rate T2	820,330	762,447	(57,883)	(7.1)
Customer 47	Rate T2	1,192,074	1,168,246	(23,828)	(2.0)
Customer 48	Rate T2	1,073,332	1,006,110	(67,222)	(6.3)
Customer 49	Rate T2	1,312,872	1,309,569	(3,303)	(0.3)
Customer 50	Rate T2	1,394,087	1,194,373	(199,714)	(14.3)
Customer 51	Rate T2	2,154,750	2,053,372	(101,378)	(4.7)
Customer 52	Rate T2	1,897,176	1,654,410	(242,766)	(12.8)
Customer 53	Rate T2	2,129,710	1,806,544	(323,166)	(15.2)
Customer 54	Rate T2	2,366,153	1,919,752	(446,401)	(18.9)
Customer 55	Rate T2	2,225,734	1,962,540	(263,194)	(11.8)
Customer 56	Rate T2	2,483,231	2,143,945	(339,287)	(13.7)
Customer 57	Rate T2	3,938,286	3,344,998	(593,288)	(15.1)
Customer 58	Rate T2	4,981,287	4,283,886	(697,401)	(14.0)
Customer 59	Rate T2	4,637,274	4,032,344	(604,930)	(13.0)

Notes:

- (1) Calculation of bill includes monthly customer charge, firm transportation demand and firm transportation commodity portions only.
- (2) Grey shading includes customers with a bill impact greater than 2%.



RP-2003-0063

EB-2003-0087

EB-2003-0097

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

AND IN THE MATTER OF an Application by Union Gas
Limited for an Order or Orders approving or fixing just and
reasonable rates and other charges for the sale, distribution,
storage, and transmission of gas for the period commencing
January 1, 2004.

BEFORE:

Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

concerns about the operation of Union's risk management program, it is open to them in future proceedings to bring expert evidence recommending appropriate changes to the program.

The Board notes that LPMA and VECC supported the risk management program, but argued that there was a need for increased reporting requirements. This position was characterized by Union as leading to unnecessary and inappropriate micro-management. The Board believes that Union's commitment to file an updated risk management policy, and at the time of deferral account disposition to provide all relevant data for an assessment of the cost impacts and compliance with the policy is sufficient to deal with these concerns.

The Board finds that Union's risk management program does provide value to ratepayers and is, therefore, appropriate, and that the specific changes Union is proposing to implement in the 2004 rate year are reasonable and provide an opportunity to enhance the value of the program.

2.2 Weather Normalization

Union's Request

Union proposes to change its weather normalization methodology and to recover the cost consequences in its rates. This proposal was supported by written evidence produced for Union by Weather Bank Inc (WB) and by Dr. Andrew Weaver, a professor of climatology at the University of Victoria.

Background

Normal weather is defined in terms of heating degree days ("HDD"), calculated on the variances in daily temperatures below 18° C. For example, if the mean daily temperature is 11°C, there are 18 - 11 = 7 HDDs on that day. If the mean daily temperature is 18° C or higher, there are no HDDs.

Weather normalization is used in forecasting demand for the general service classes (M2, R1 and R10), storage and transportation allocations, gas supply planning, and rate design. Weather normalization is also used to estimate average use per customer, which, when multiplied by the forecast number of customers, yields a demand forecast. Although weather normalization is not used directly to forecast demand for other classes, it can have impacts on other rate classes by affecting load balancing costs.

Union has historically used a 30-year rolling average method. In the RP-2002-0130 proceeding respecting 2003 rates, Union proposed to introduce a twenty-year trend methodology similar to what it was already using for distribution system planning and its gas supply portfolio. The impact of extending its use to ratemaking would have been to increase the revenue requirement to be captured in 2003 rates by an extra \$13.7 million. At the time, Union was under a three-year trial PBR plan and sought to make this change as a non-routine adjustment. The PBR plan had been established on the basis of the existing weather normalization methodology. The Board denied Union's application on the basis that the weather risk was to be managed by Union as part of its PBR plan, and it was not appropriate to effect a change of this magnitude in the course of the PBR period.

Union's Position

Union's evidence states that, based on data from 1985 to 2000, the 30-year average weather normalization methodology consistently overestimates the heating demand by customers by about 7.6%. Mr. Fogwill of Union testified that the impact of a 1% variance in HDDs is about \$3.0 million in annual delivery revenues.

Union argued that the 30-year average method assumed a static long run climatic condition and that this assumption was invalid. It noted that over the last 17 years, the method over-forecast HDDs fourteen times, and under-forecast HDDs only three times. Union cited Dr. Weaver's evidence in respect of climate change and global warming in support of its contention that variations were no longer symmetrical around the weather normal estimate.

In addition, Union stated that "... the yearly variability in temperature is increasing, with the standard deviation of 166 HDDs over the period 1956-1985 period increasing to 310 HDDs over the period 1972-2001. Union stated that its consultant, WB, agreed with Dr. Weaver that global warming was occurring. WB also supported Union's claim that volatility was increasing, noting an increase in the frequency of weather events such as El Nino and La Nina.

Dr. Weaver stated that there was an increase in global average temperature of approximately 0.6 degrees Centigrade (+/- 2°) over the twentieth century. He stated the warming trend occurred during two periods, 1901-1945 and 1976-2000 and were separated by a cooling period between 1945-1976. Union stated that 0.6 degrees per century corresponded to 1.6 HDDs per year. Dr. Weaver gave an estimate of a global average temperature increase of 2°C, but qualified this figure as it applies to Ontario, due to the amplification effect of Ontario geography.

Mr. Root of WB testified that in his experience extreme weather events had become much more common over the last 20 years. He suggested that use of the 20-year trend method would have the effect of mitigating the volatility associated with such extreme weather.

Union listed five objectives that its proposed normalization method was assessed against:

- 1 symmetry – actual HDDs are expected to vary positively and negatively equally with respect to the forecast HDDs;
- 2 accuracy – over time the variance between actual and normal HDDs should be minimized;
- 3 stability – the year over year normalized HDD estimate should not vary significantly when measured using standard deviation;
- 4 sustainability – the method should not require significant amendments in the near future; and

5 simplicity – the method should be easy to use.

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The 20 year trend methodology uses data from twelve Environment Canada weather stations in Union's franchise area. The data is weighted by the throughput volumes in the region associated with each weather station. Union then applied ordinary least squares regression analysis to find the best fit to the weighted HDD.

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Union ranked seven weather normalization methods by weighting and applying the above five objectives. The weightings applied by Union were on a scale from 1 to 3 as follows:

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1 symmetry was given a weight of 3,

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2 accuracy was given a weight of 2, and

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3 stability, sustainability, and simplicity were given a weight of 1.

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Based on these measures, Union ranked the methods in order, from best to worst, as follows: 20-year trend with forecast information, 20-year trend, 30-year trend, 38-year trend, 20-year average, 10-year average, and 30-year average. Union proposed the 20-year trend method rather than the 20-year trend with forecast information method, arguing that the latter was far more complex and that it relied upon a third party's proprietary model and therefore might not be sustainable.

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Union stated that the rate impact of adopting the new method would be an increase of \$20.4 million in the revenue requirement which would be allocated to the M2, R01, and R10 general service classes only. These impacts resulted from an approximately 3.9% deviation between the 30-year weather average and the proposed 20-year trend weather normalization methodologies. Union proposed to allocate the revenue impacts only to the general service classes because these are the only classes for which Union forecasts demand using weather normalization.

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Union's witness testified that other than EGDI, whose weather normalization methodology includes a trending component and a moving average component, no other Canadian utility uses a trend method for this purpose. Further, Union was unable to cite any U.S. gas utility that uses a 20-year trend method.

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Union noted that Environment Canada, the U.S. Weather Service, and the World Meteorological Organization all used a 30-year average weather normalization methodology. Dr. Weaver was unaware of any national or international meteorological organization that has changed from a 30-year average to a 20-year trend method, but he pointed out that those groups use the methodology to define a reference value and not as an indicator of the rate at which the reference is changing.

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Although Union agreed that the data in evidence showed increasing variability over time, i.e., the data may exhibit heteroscedasticity, Union stated that it had not statistically tested for heteroscedasticity. Union also stated that the data it was relying on was time series data whose mean and variance

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were changing over time. The data were non-stationary and the validity of standard statistical tests was in question if the data were not stationary.

Board Findings

The Board is asked to approve a change in the weather normalization methodology that is applied to M2, R1 and R10 customer class forecast volumes. Union proposes to apply the 20 year trend methodology currently used to allocate upstream transportation and storage to unbundled customers.

The five objectives and associated weights proposed by Union are a good starting point for establishing a proper weather normalization methodology. The issue for the Board to consider is whether the 20 year trend methodology is a superior forecasting tool than the current 30 year moving average. The impetus to change methodologies is the hypothesis, supported by the evidence of Dr. Weaver, of a global warming trend.

Dr. Weaver's evidence does not support any particular weather normalization method. A number of parties argued for continuation of the 30 year methodology. LPMA and IGUA criticized the statistical analysis done by Union and argued for the continuation of the current practice, or a 20 year method with various proposed revenue adjustment mechanisms. Many parties pointed out that the 20 year proposed methodology would result in a net increase in rates.

IGUA and FONOM argued for a phasing in of any change in methodology. Union rejected this proposal and claimed that this would result in it failing to recover its costs, except during colder than normal weather.

Ratepayers are at risk for unutilized demand charges if the methodology overforecasts HDDs, but the ratepayers are also at risk for the cost of increased winter spot purchases if the methodology underforecasts HDDs.

The Board is concerned with the lack of clarity with respect to the statistical evidence. A number of parties explored whether an estimator derived from ordinary least squares was more or less efficient than using a more sophisticated regression technique. Union's inability to respond clearly is of concern, especially given the large impact that the proposed change in methodology has on its revenue requirement.

Both the 20-year trend and the 30-year average normalization methodologies have advantages in their application. The 20-year trend may track more through the middle of the data and will respond more quickly to changes in short-run trends, but will be more volatile. The 30-year average will respond more slowly to changes but it will be less volatile.

Union was unable to demonstrate that its proposal provided a clear and unambiguous improvement over the 30 year methodology. Nor is the Board convinced that the cited case: Hemlock Valley Electrical Association v. British Columbia Utilities Commission provides any precedent as to

whether it is open to the Board in this case to choose a phased in approach. The OEB Act gives the Board clear authority to adopt any methodology it considers appropriate when setting rates.

In order to test the suitability of changing the normalization methodology, and in consideration of the principle of minimizing rate shock, the Board will allow Union, for 2004, to forecast HDDs based on a 70:30 weighting of the 30-year average forecast and 20-year trend forecast respectively. For each year thereafter, the Board will consider 5% declines and inclines to the weighting of the 30 year and 20 year methodology respectively until such time as a 50:50 weighting is in place.

With respect to operational planning, the Board directs Union to use the same forecast for operations planning as is used all other purposes. The Board also directs Union to report on the outcomes of using the hybrid model annually.

2.3 Affiliate Relations

Union's Request

Union seeks to recover in rates the costs it incurs as a result of its shared services arrangements with its affiliates. These costs are \$28.7 million in total.

Background

Duke Energy Corporation ("Duke") completed the purchase of Westcoast Energy Inc. ("WEI"), the parent company of Union, in March 2002. Following this transaction, Union became a participant in Duke's shared services business model. The use of this model results in the sharing of a broad range of senior management and support services across Duke's many business units, creating inter-company transactions between the Duke business units as they pay for services received, and charge for services provided to other units.

Union has previously shared services with affiliated companies through the WEI Corporate Centre. Under the Duke shared services business model, to which it is now subject, the WEI Corporate Centre is no longer the only, nor even the primary, provider of shared services to Union.

There are now 24 activities being performed by or for Union on a shared services basis. Union provided a listing of the operational and functional groups that are operating under the shared services structure, and attempted to identify for each of these groups the benefits to Union of procuring the activities on a shared services basis.

Under the Duke shared services business model, Union would continue to provide services to affiliated companies in 2004. As in the past, these outbound services would be provided using staff and assets primarily required to support the regulated business. The affiliates receiving services from Union are:

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:	Del. Rev.	Sales. Rev.
		<u>10³ m³</u>	<u>\$000's¹</u>	<u>\$000's¹</u>
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	<u>1,047</u>	<u>36</u>	<u>265</u>
Total	Volumes	<u>144,681</u>	<u>6,956</u>	<u>35,480</u>

		If 50:50 Blended Normal		
		Volumes:	Del. Rev.	Sales. Rev.
		<u>10³ m³</u>	<u>\$000's¹</u>	<u>\$000's¹</u>
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	<u>951</u>	<u>33</u>	<u>273</u>
Total	Volumes	<u>131,528</u>	<u>6,324</u>	<u>38,578</u>

		If 40:60 Blended Normal		
		Volumes	Del. Rev.	Sales. Rev.
		<u>10³ m³</u>	<u>\$000's¹</u>	<u>\$000's¹</u>
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	<u>761</u>	<u>26</u>	<u>219</u>
Total	Volumes	<u>105,223</u>	<u>5,059</u>	<u>30,862</u>

Note: 1 at Jan 2012 QRAM rates

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit H3, Tab 4, Schedule 1

Union's customer bill impacts reveal a significant difference between delivery rate impacts for southern customers as compared to the northern and eastern customers. While customers in the Southern Service area will experience an increase of \$19, customers in the Northern, Eastern and Western Service areas will experience an increase anywhere between \$59 and \$76.

- a) Please explain the reasons for the significant difference between rate impacts for southern customers as compared to customers of other service areas.
- b) Has Union in the past cross-subsidized the residential rate classes. If yes, please provide details of the cross-subsidies and the period in which these occurred. Also, please explain the reasons for doing so.
- c) Has Union considered any rate mitigation measures to reduce the impact for Northern, Eastern and Western Service area customers? If no, why not?

Response:

- a) As shown at Exhibit H3, Tab 1, Schedule 1, Updated, column (i), proposed Union North delivery rates are increasing by an average of 20%. Union South delivery rates are increasing by an average of 7%. The result is an overall increase in proposed in-franchise delivery rates of approximately 10%.

The delivery bill impact in Union North is \$59 to \$76 for the average residential customer. In Union South, the delivery bill impact is \$19 for the average residential customer.

There are two factors causing Union North delivery rates to increase by an average of 20%, while Union South delivery rates increase by an average of 7%. The first is that Union North delivery revenue has decreased as a percentage of total delivery revenue from 2007 Board-approved to 2013 forecast levels. At the same time, the Union North delivery-related revenue requirement has increased as a percentage of the total delivery-related revenue requirement. Please see Attachment 1.

As shown at Attachment 1, lines 1-3, at 2007 Board-approved levels Union North delivery revenue represented 27% of total delivery revenue, while Union South represented 73%. In Union's 2013 revenue forecast, Union North delivery revenue represents 26% of total

delivery revenue, while Union South represents 74%. In dollar terms, Union North delivery revenue has declined by \$1.8 million while Union South delivery revenue has increased by \$9.9 million.

Given that delivery rates have been essentially flat over the IR term, the decline in Union North delivery revenue demonstrates the loss of volumes in Union North compared to Union South. As shown at Attachment 1, lines 4-6, Union North Rate 01 volumes have decreased by approximately 5% from 2007 Board-approved to 2013 forecast levels, while Union South Rate M1 volumes have increased marginally. The relative change in the 2013 revenue forecast compared to 2007 Board-approved levels by operating area is driving an increase in Union North delivery rates relative to Union South delivery rates.

Concurrently, as described above, the Union North delivery-related revenue requirement has increased as a percentage of total delivery-related revenue requirement from 2007 Board-approved to 2013 forecast levels.

As shown at Attachment 1, lines 19-21, at 2007 Board-approved levels the Union North delivery-related revenue requirement represented 27% of the total revenue requirement, while Union South represented 73%. In Union's 2013 forecast, the Union North delivery-related revenue requirement represents 29% of the total revenue requirement, while Union South represents 71%. In dollar terms, the Union North revenue requirement has increased by \$32.9 million while the Union South revenue requirement has increased by \$33.8 million. Although the relative share of the Union North/South revenue requirement has only changed moderately, the increase in costs to Union North account for approximately 50% of the 2013 revenue deficiency.

As per Exhibit H3, Tab 1, Schedule 1, Updated, page 1, the Union North delivery-related revenue deficiency resulting from Union's 2013 cost of service forecast is \$46.375 million, while the Union South delivery-related revenue deficiency is \$46.066 million. After including the ratepayer portion of forecast S&T transactional service revenue in the revenue stream for ratemaking purposes, Union has proposed to recover a deficiency of \$35.908 million in Union North delivery rates and \$35.669 million in Union South delivery rates.

As forecast 2013 Union North delivery revenue is roughly 1/3 of Union South delivery revenue, the recovery of a \$36 million deficiency in each operating area results in a Union North delivery rate increase of 20% that is approximately three times the Union South delivery rate increase of 7%.

Attachment 1 also provides a breakdown of capital and O&M-related revenue requirements from 2007 Board-approved to 2013 proposed levels. Further, Union has provided additional information on the drivers increasing the Union North delivery-related revenue requirement relative to Union South below:

- Local Storage Plant – Hagar LNG net utility plant has increased from the 2007 Board-approved levels due to plant additions of \$8.2 million, a transfer of \$1.0 million of assets, and a change in the depreciation due to the extended plant life from 2012. The increase in the 2013 Union North revenue requirement compared to 2007 Board-approved levels is approximately \$0.9 million.
- Depreciation Expense – The Union North distribution depreciation expense has increased by \$6.8 million and Union South distribution depreciation expense has increased by \$7.2 million. The Union North depreciation expense is increasing at a higher percentage of Union North revenue requirement compared to Union South due to a variance between 2007 Board-approved levels and 2007 actuals.

The 2007 Board-approved level of Union North depreciation expense was \$0.7 million lower than 2007 actuals, while the 2007 Board-approved level of Union South depreciation expense was \$1.7 million higher than 2007 actuals. The disproportionate increase to the Union North revenue requirement from 2007 Board-approved levels to the proposed 2013 revenue requirement is \$1.7 million.

- Distribution O&M – Union North distribution O&M has increased by \$3.8 million and Union South distribution O&M by \$2.4 million from 2007 Board-approved levels to the 2013 forecast. The 2013 O&M budget includes more detail than the 2007 forecast, which makes a comparison between Union North and Union South difficult. One specific item which has increased for both Union North and Union South are line locates, which have both increased by approximately \$1.5 million since the 2007 Board-approved forecast. The disproportionate increase to the Union North revenue requirement from Board-approved 2007 to the proposed 2013 revenue requirement is \$2.8 million, which includes the allocation of direct and indirect costs. The difference calculation assumes that the Union North and Union South distribution O&M increased at same rate of 11% since the Board-approved 2007 forecast. Of this increase, the disproportionate increase of line locates results in a Union North revenue requirement increase of \$0.7 million.
- Sales and Promotion Costs – In the 2007 Board-approved cost allocation study, 97% of sales and promotion supervision costs were allocated to Union South in-franchise customers, excluding gas supply and DSM direct assignments. The addition of DSM related costs to the Sales and Promotion category in the cost study resulted in most of the costs being classified to demand and allocated to only Union South in-franchise customers. In the 2013 cost allocation study, Union corrected the classification to exclude DSM. This change results in costs being classified as customer-related and allocated based on an analysis of sales activities. This correction results in 75% of the sales and promotion supervision costs being allocated to Union South and 25% to Union North, for a Union North revenue requirement increase of \$1.9 million.

- General Operating and Engineering O&M Costs – The general operating and engineering operating expenses are functionalized based on an analysis of activities. Examples of the costs in this category include planning and dispatch, engineering, geology, capacity management, S&T sales, and gas control. In the 2007 Board-approved cost allocation study, the analysis was based on a sample of the internal work orders. In 2013, the analysis includes a larger sample size representing 91% of the operating expenses. The increased sample size results in a decrease of costs functionalized to transmission and purchase production functions and an increase to distribution. The functionalization update results in an increased allocation of \$4.7 million delivery-related revenue requirement to Union North rate classes.
- b) Union's historical revenue-to-cost ratios for General Service rate classes have minimized the cross-subsidization of residential customers in Union's rate classes.
- c) Union has not proposed any rate mitigation measures to reduce the rate impacts on Union North customers specifically. Union's proposed 2013 rates for both Union South and Union North appropriately recover the 2013 test year revenue requirement and reflect the differing costs associated with serving each delivery area.

Notwithstanding Union's view that its 2013 rate proposals are appropriate, Union has considered a number of rate mitigation measures. They are:

1. At Exhibit F1, Tab 1, Union has proposed to increase the equity component of its capital structure from 36% to 40% to align with capital structures of other North American natural gas and electricity utilities of similar risk. The revenue requirement impact associated with this proposal is approximately \$15 million. To manage the overall revenue requirement and rate impacts, increasing the equity component of Union's capital structure could be phased in over 2 to 4 years.
2. At Exhibit C1, Tab 5, Union is proposing to change its weather normalization method from the current 55:45 (55% 30 year average and 45% 20 year declining trend) method to 100% 20 year declining trend. This proposal increases Union's 2013 revenue deficiency by approximately \$7 million. To manage the overall revenue requirement and rate impacts, implementation of the 20 year declining trend weather normalization methods could be phased in over 2 to 5 years.
3. As indicated at Exhibit C1, Tab 3, based on TCPL's proposal to eliminate the FT-RAM program, Union has not included any FT-RAM revenue in its 2013 short-term transportation and exchange revenue forecast. In the alternative, Union could partially mitigate 2013 rate impacts in Union North by including revenue associated with FT-RAM in Union North delivery rates on the assumption that TCPL is not successful in eliminating the FT-RAM program. If Union were to take this approach, Union would require deferral account protection to cover the possibility that the FT-RAM program is eliminated or materially changed as a result of TCPL's mainline rate proceeding.

4. Finally, the Board could find that, in the course of setting just and reasonable rates, it would be in the public interest to allow the 2013 revenue-to-cost ratios for Union South and Union North general service rate classes to be adjusted such that the gap between Union South and Union North delivery rates is reduced or eliminated.

Total In-franchise Delivery Revenue and Revenue Requirement
2007 Board-Approved vs. 2013 Forecast

Line No.	Particulars (\$000's)	2007 Board-Approved		2013 Forecast		Difference 2013 less 2007		% Δ
		(a)	(b)	(c)	(d)	(e) = (c-a)	(f)	(g) = (e/a)
<u>Revenue</u>								
1	Union North Delivery (1)	180,861	27%	179,100	26%	(1,761)		-1%
2	Union South Delivery & Storage (2)	500,500	73%	510,391	74%	9,891		2%
3	Total In-franchise Delivery Revenue	681,361	100%	689,491	100%	8,130		1%
<u>Billing Units (10³m³)</u>								
4	Rate 01 Delivery (3)	905,311	24%	855,598	23%	(49,713)		-5%
5	Rate M1 Delivery (4)	2,862,265	76%	2,876,411	77%	14,146		0%
6	Total Rate 01 and Rate M1 Delivery	3,767,576	100%	3,732,009	100%	(35,567)		-1%
<u>Revenue Requirement</u>								
7	Union North Capital-Related Costs	122,605	30%	133,362	30%	10,757	30%	9%
8	Union South Capital-Related Costs	288,330	70%	313,030	70%	24,700	70%	9%
9	Total In-franchise Capital-Related Costs (5)	410,935	100%	446,392	100%	35,457	100%	9%
10	Union North O&M Costs	72,177	25%	94,886	27%	22,709	42%	31%
11	Union South O&M Costs	220,835	75%	252,601	73%	31,766	58%	14%
12	Total In-franchise O&M Costs	293,012	100%	347,487	100%	54,475	100%	19%
13	Union North Cost of Gas Costs	3,540	10%	2,763	25%	(777)	3%	-22%
14	Union South Cost of Gas Costs	32,137	90%	8,422	75%	(23,715)	97%	-74%
15	Total In-franchise Cost of Gas Costs (6)	35,677	100%	11,185	100%	(24,492)	100%	-69%
16	Union North Other Revenue	(5,770)	24%	(5,535)	24%	234	18%	-4%
17	Union South Other Revenue	(18,664)	76%	(17,596)	76%	1,068	82%	-6%
18	Total In-franchise Other Revenue	(24,434)	100%	(23,131)	100%	1,302	100%	-5%
19	Union North Revenue Requirement (1)	192,552	27%	225,475	29%	32,924	49%	17%
20	Union South Revenue Requirement (2)	522,637	73%	556,457	71%	33,820	51%	6%
21	Total In-franchise Revenue Requirement	715,189	100%	781,932	100%	66,744	100%	9%

Notes:

- (1) Union North revenue and revenue requirement for delivery rates, as per EB-2005-0520, Rate Order, Working Papers, Schedule 5, page 1, line 7 and EB-2011-0210, Exhibit H3, Tab 1, Schedule 1, Updated, page 1, line 6.
- (2) Union South revenue and revenue requirement for Union South delivery and storage rates, as per EB-2005-0520, Rate Order, Working Papers, Schedule 5, page 1, line 16 and EB-2011-0210, Exhibit H3, Tab 1, Schedule 1, Updated, line 17.
- (3) Rate O1 delivery billing units, as per EB-2005-0520, Rate Order, Working Papers, Schedule 6, page 1, line 12, column (a) and EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, Updated, page 1, line 7, column (a).
- (4) Rate M1 delivery billing units, as per EB-2005-0520, Rate Order, Working Papers, Schedule 21, line 12, column (a) and EB-2011-0210, Exhibit H3, Tab 1, Schedule 2, Updated, page 5, line 5, column (a).
- (5) Capital-related costs include return, taxes and depreciation expense.
- (6) The Cost of Gas related costs include compressor fuel. The costs exclude gas supply commodity and gas supply commodity fuel.

1 3.2/ Detailed Forecast Methodology

2 The remainder of the contract market is comprised of approximately 60 customers (Steel,
3 Chemical and Refinery, Power and Key market sectors). This group represents 12% of customers
4 and accounts for approximately 60% of volume throughput and revenue in the contract market.
5 Union has historically used detailed, bottom-up forecasts for this group and continues to use this
6 approach given its extensive understanding of these accounts through ongoing interactions
7 between the customer and the account manager. These large industrial and power generation
8 customers are sophisticated, major consumers of energy. Using a combination of historical
9 consumption information and knowledge of specific customer production plans and expectations,
10 the account manager builds the customer forecast. The account manager seeks input from the
11 customer when formulating the forecast and discusses the final forecast with them once
12 completed.

13
14 **4/ CONTRACT CUSTOMER DEMAND COMPARISONS**

15 Tables 1 and 2 compare consumption volume and revenue between 2007 Board-approved and
16 2013 forecast by market sector.

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

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.

Table 1

Volume Comparison by Market Sector
2007 Board-approved through 2013 Forecast
(10⁶m³)

Line No.	Market Sector	2007 Board-approved	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
1	Power	1,831	2,078	1,659	1,854	2,349	2,464	2,215	2,189
2	Steel/Chemical/ Refinery	3,374	3,272	3,523	2,971	3,271	3,582	3,866	3,734
3	LCI/Key	2,825	2,806	2,697	2,218	2,163	2,180	2,110	2,117
4	Greenhouse	146	173	203	197	246	287	303	315
5	Wholesale/REM	<u>346</u>	<u>297</u>	<u>305</u>	<u>319</u>	<u>315</u>	<u>324</u>	<u>330</u>	<u>334</u>
6	Totals ⁽¹⁾	<u>8,521</u>	<u>8,625</u>	<u>8,386</u>	<u>7,560</u>	<u>8,344</u>	<u>8,837</u>	<u>8,824</u>	<u>8,689</u>

(1) Excludes MAV volumes.

Table 2

Revenue Comparison by Market Sector
2007 Board-approved through 2013 Forecast
(\$ Millions)

Line No.	Market Sector	2007 Board-approved	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
1	Power	23.5	26.8	26.3	29.0	32.2	32.7	29.7	29.5
2	Steel/Chemical/Refinery	37.2	38.5	37.7	37.0	36.7	38.4	36.1	35.5
3	LCI/Key	44.8	45.1	43.9	39.5	36.8	36.4	35.2	34.7
4	Greenhouse	4.0	3.9	5.2	4.9	5.8	6.3	6.2	6.5
5	Wholesale/REM	<u>6.2</u>	<u>5.5</u>	<u>5.7</u>	<u>5.8</u>	<u>5.7</u>	<u>5.5</u>	<u>5.4</u>	<u>5.4</u>
6	Totals ⁽¹⁾	<u>115.7</u>	<u>119.8</u>	<u>118.8</u>	<u>116.2</u>	<u>117.2</u>	<u>119.3</u>	<u>112.6</u>	<u>111.6</u>

(1) 2007 (actual) to 2013 revenue is calculated using Q1, 2011 rates.

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

Undertaking of Mr. Thompson
To Ms. Van Der Paelt

Please provide overrun forecast for all markets.

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

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 (10³m³)					
	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.