June 8, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: EB-2012-0087 - Union Gas Limited - 2011 Earnings Sharing & Disposition of Deferral Accounts and Other Balances – Responses to Interrogatories

Please find attached Union's responses to the EB-2012-0087 interrogatories.

Union has filed the responses to Board Staff question 9 b) and BOMA question 2 c) under separate confidential cover. Due to the sensitive information included in the responses, Union requests that the Board maintain these responses as confidential per the Practice Direction on Confidential Filings. Intervenors wishing to view these responses must execute a Declaration and Undertaking and forward it to Union.

If you have any questions with respect to this submission please contact me at (519) 436-5473.

Yours truly,

[original signed by]

Karen Hockin
Manager, Regulatory Initiatives

cc Crawford Smith (Torys)
EB-2012-0087 Intervenors

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 1 / Pages 4-8
Exhibit A / Tab 1 / Schedules 6-7

Preamble: Union noted that there is a debit balance in the Short-Term Storage and Other Balancing Services deferral account of $7.137 million. Union stated that the balance is calculated by comparing the actual 2011 net revenue for Short-Term Storage and Other Balancing Services of $7.899 million to the net revenue approved by the Board of $15.829 million in the EB-2007-0606 Rate Order. Union noted that the result is a net deferral debit of $7.930 million and pursuant to the Board's Decision and Order on Draft Rate Order in EB-2011-0038 on February 29, 2012, 90% of the net deferral debit, or $7.137 million, is shared with ratepayers.
Union noted that total short-term storage revenues have fallen from $20.877 million in 2010 to $10.964 million in 2011 and that short-term storage related costs have fallen from $4.134 million in 2010 to $3.065 million in 2011.

a) Please confirm that the short-term storage margin net revenue / credit amount embedded in base rates is $11.254 million (as opposed to $15.829 million). If that is not the case, please explain why. Please confirm that the debit amount to be shared with ratepayers of $7.137 million would be reduced to $3.02 million if the calculation for sharing is done using $11.254 million as the amount embedded in base rates.

b) Please explain why short-term storage revenues have fallen by approximately 48% while costs have only decreased by approximately 26%. Please explain why O&M related costs remains static at $2.261 million regardless of revenues generated.

c) Please provide Union's best estimate of short-term storage revenues for 2012.

Response:

a) Confirmed. The short-term storage margin net revenue / credit amount embedded in base rates is $11.254 million.

The debit amount to be shared with rate payers would be reduced to $4.145 million not $3.02 million if the calculation for sharing is done using $11.254 million. The calculation of $3.02 million does not take into account the sharing of actual revenues. Please see Attachment 1 for the calculation.

b) The cost of $2.261 million are demand related costs associated with excess utility space of 7.9 PJs. These costs were calculated by comparing the Board-approved 2007 cost allocation

study to the Board-approved 2007 cost allocation study adjusted to reflect an assumed in-franchise requirement of 100 PJs (please see Exhibit B6.1 for the calculation).

These demand related costs are fixed and do not vary with the capacity sold or revenues generated.

c) Union's year to date actual short term storage revenue for the first 3 months of 2012 is $3.085 million.

UNION GAS LIMITED
Calculation of Balance in Short-Term Storage Deferral Account using CME Methodology (No. 179-70) Using CME Methodology

Line No.	Particulars ($000's)	2011
1	Actual 2011 Net Margin	7,899
2	10% Incentive to Union	(790)
3	90% of Net Margin	7,109
4	Amount Embedded in Rates	11,254
5	Ratepayer Share of Deficiency	(4,145)
6	Ratepayer Share of Deficiency as Filed by Union in EB-2012-0087	(7,137)
7	Difference in Ratepayer Share of Deficiency	2,992

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 1 / Pages 9-11
Exhibit A / Tab 1 / Schedule 2

Preamble: The evidence indicates that in accordance with previous Board-approved practice, Union is proposing to clear the recorded LRAM balance related to unaudited 2011 DSM activities.

a) Please indicate when the audited balances will be available and filed with the Board.

b) Please explain the reason for the increase in 2011 unaudited LRAM volumes of 163,766 103m3 from 2010 audited LRAM volumes of 121,116 103m3. Please provide a high-level list of conservation projects that resulted in the increased volume savings for 2011.

Response:

a) Union will file the final audited 2011 Annual Report, which contains the audited LRAM balance, with the Board on June 30th 2012.

b) The volume variance of 42,650 10^3m^3 is primarily due to increased natural gas savings attributable to custom projects. The overall number of Distribution Contract custom projects increased by 188 in 2011. The custom projects substantially increased m^3 savings from 2010 to 2011 in the Industrial T1 and Industrial M5 rate classes.

Please see Attachment 1 for a list of Distribution Contract custom projects, including volume savings.

UNION GAS LIMITED
Distribution Contract Custom Projects

Line No.	End User Account LRAM Rate Class	Project Completed Number	Project Equipment Type	Total Adjusted Gross TRC ($) w/ RR	Total Adjusted Gas Savings (m^3) w/ RR
	(a)	(b)	(c)	(d)	(e)
1	10 North Industrial	2011-IND-0078	Insulation	9,973.07	13,931
2	10 North Industrial	2011-IND-0066	Boiler - Hot Water	148,945.13	58,494
3	10 North Industrial	2011-IND-0291	Controls	71,578.72	28,424
4	Total 10 North Industrial			230,496.92	100,849
5	100 North Industrial	2011-IND-0267	Other	6,957,101.96	2,354,679
6	100 North Industrial	2011-IND-0660	Other	1,102,753.98	363,189
7	100 North Industrial	2011-IND-0120	Steam Distribution System	9,450.39	5,492
8	100 North Industrial	2011-IND-0270	Heat Recovery System	2,569,830.80	832,312
9	100 North Industrial	2011-IND-0585	Steam Distribution System	743,926.55	256,705
10	100 North Industrial	2011-IND-0603	Steam Distribution System	107,183.53	63,276
11	100 North Industrial	2011-IND-0030	Insulation	128,674.36	162,259
12	100 North Industrial	2011-IND-0609	Gas Turbine	33,420.21	130,762
13	100 North Industrial	2011-IND-0446	Heat Recovery System	393,865.12	473,997
14	100 North Industrial	2011-IND-0597	Insulation	256,673.01	88,934
15	100 North Industrial	2011-IND-0586	Gas Turbine	690,152.33	238,639
16	100 North Industrial	2011-IND-0600	Insulation	153,069.85	103,186
17	100 North Industrial	2011-IND-0566	Steam Distribution System	3,537,496.87	1,201,552
18	100 North Industrial	2011-IND-0028	Gas Turbine	27,584.00	108,968
19	100 North Industrial	2011-IND-0509	Steam Distribution System	481,957.09	165,600
20	100 North Industrial	2011-IND-0029	Other	55,286.91	229,059
21	100 North Industrial	2011-IND-0075	Steam Distribution System	38,871.69	23,160
22	100 North Industrial	2011-IND-0602	Steam Distribution System	132,236.01	44,614
23	100 North Industrial	2011-IND-0310	Controls	92,552.53	65,648
24	100 North Industrial	2011-IND-0653	Other	1,165,808.09	490,229
25	100 North Industrial	2011-IND-0618	Insulation	283,162.11	101,531
26	100 North Industrial	2011-IND-0552	Steam Distribution System	437,500.36	274,987
27	100 North Industrial	2011-IND-0450	Other	799,733.76	324,054
28	100 North Industrial	2011-IND-0119	Heat Recovery System	283,142.97	154,215
29	100 North Industrial	2011-IND-0625	Steam Distribution System	259,088.60	157,831
30	100 North Industrial	2011-IND-0581	Insulation	1,028,240.23	341,995
31	100 North Industrial	2011-IND-0148	Boiler - Steam	429,162.36	470,751
32	100 North Industrial	2011-IND-0122	Other	909,177.69	320,131
33	100 North Industrial	2011-IND-0031	Steam Distribution System	105,389.13	82,809
34	100 North Industrial	2011-IND-0451	Gas Turbine	6,472,805.04	2,436,221
35	Total 100 North Industrial			29,685,297.54	12,066,785
36	20 North Industrial	2011-IND-0335	Steam Distribution System	660,557.03	317,845
37	20 North Industrial	2011-IND-0324	Insulation	9,412.64	7,613
38	20 North Industrial	2011-IND-0067	Boiler - Hot Water	141,770.70	66,903
39	20 North Industrial	2011-IND-0330	Other	1,050,680.67	458,869
40	20 North Industrial	2011-IND-0606	Controls	46,228.18	18,827
41	20 North Industrial	2011-IND-0110	Heat Recovery System	471,988.15	172,344
42	20 North Industrial	2011-IND-0077	Other	10,567.04	10,542
43	20 North Industrial	2011-IND-0467	Steam Distribution System	29,848.10	17,389
44	20 North Industrial	2011-IND-0225	Controls	573,460.05	222,435
45	20 North Industrial	2011-IND-0414	Controls	544,613.13	163,617
46	20 North Industrial	2011-IND-0068	Other	264,428.30	97,556
47	20 North Industrial	2011-IND-0006	Steam Distribution System	105,077.50	63,811
48	20 North Industrial	2011-IND-0303	Heat Recovery System	24,039.88	13,913
49	20 North Industrial	2011-IND-0452	Controls	552,609.58	164,086
50	20 North Industrial	2011-IND-0333	Insulation	27,636.26	14,591
51	20 North Industrial	2011-IND-0328	Controls	1,312,042.75	459,741
52	20 North Industrial	2011-IND-0608	Insulation	46,739.14	18,962
53	20 North Industrial	2011-IND-0096	Insulation	120,671.74	47,634

54	20 North Industrial	2011-IND-0623	Other	425,587.90	151,882
55	20 North Industrial	2011-IND-0076	Heat Recovery System	5,174,032.92	1,677,349
56	20 North Industrial	2011-IND-0617	Steam Distribution System	336,525.26	216,389
57	20 North Industrial	2011-IND-0621	Other	26,577.88	33,535
58	Total 20 North Industrial			11,955,094.76	4,415,832
59	M1 South Industrial	2011-IND-0253	Heat Recovery System	9,838.88	6,499
60	M1 South Industrial	2011-IND-0432	Other	2,077.64	63,260
61	M1 South Industrial	2011-IND-0379	Heat Recovery System	2,552,530.40	908,610
62	M1 South Industrial	2011-IND-0283	Insulation	303,944.22	156,312
63	Total M1 South Industrial			2,868,391.13	1,134,680
64	M2 South Commercial	2011-IND-0143	Other	28,791.52	26,603
65	M2 South Commercial	2011-IND-0473	Other	10,414.05	13,854
66	Total M2 South Commercial			39,205.56	40,457
67	M2 South Industrial	2011-IND-0004	Boiler - Hot Water	91,097.83	46,300
68	M2 South Industrial	2011-IND-0017	Shaft Melter - Aluminum	488,336.32	260,624
69	M2 South Industrial	2011-IND-0034	Other	105,861.91	127,227
70	M2 South Industrial	2011-IND-0038	Controls	492,900.76	42,158
71	M2 South Industrial	2011-IND-0039	Controls	1,258,366.79	162,412
72	M2 South Industrial	2011-IND-0381	Other	12,307.79	15,834
73	M2 South Industrial	2011-IND-0040	Controls	49,802.73	11,639
74	M2 South Industrial	2011-IND-0050	Burners	184,410.04	63,309
75	M2 South Industrial	2011-IND-0087	Insulation	7,466.18	3,210
76	M2 South Industrial	2011-IND-0095	Other	16,557.68	21,496
77	M2 South Industrial	2011-IND-0098	Other	11,301.79	6,862
78	M2 South Industrial	2011-IND-0144	Controls	83,964.89	41,235
79	M2 South Industrial	2011-IND-0194	Other	178.49	1,106
80	M2 South Industrial	2011-IND-0242	Controls	195,069.81	65,155
81	M2 South Industrial	2011-IND-0254	Other	4,427.62	5,938
82	M2 South Industrial	2011-IND-0255	Other	3,670.60	4,750
83	M2 South Industrial	2011-IND-0284	Insulation	80,998.20	33,107
84	M2 South Industrial	2011-IND-0300	Controls	158,034.92	70,498
85	M2 South Industrial	2011-IND-0359	Other	9,192.14	11,875
86	M2 South Industrial	2011-IND-0364	Heat Recovery System	47,731.92	17,665
87	M2 South Industrial	2011-IND-0365	Controls	47,556.66	16,317
88	M2 South Industrial	2011-IND-0367	Heat Recovery System	1,003,411.75	457,259
89	M2 South Industrial	2011-IND-0373	Other	39,669.13	47,501
90	M2 South Industrial	2011-IND-0377	Insulation	19,926.39	9,642
91	M2 South Industrial	2011-IND-0382	Other	18,111.50	23,750
92	M2 South Industrial	2011-IND-0383	Other	8,949.49	11,875
93	M2 South Industrial	2011-IND-0443	Heat Recovery System	13,924.53	63,890
94	M2 South Industrial	2011-IND-0445	Heat Recovery System	9,085.82	43,570
95	M2 South Industrial	2011-IND-0466	Other	197,999.18	45,402
96	M2 South Industrial	2011-IND-0499	Insulation	49,381.60	32,717
97	M2 South Industrial	2011-IND-0511	Controls	490,707.14	176,163
98	M2 South Industrial	2011-IND-0526	Make Up Air	165,007.58	34,386
99	M2 South Industrial	2011-IND-0583	Heat Recovery System	940,521.86	412,640
100	M2 South Industrial	2011-IND-0642	Other	7,768.52	9,896
101	M2 South Industrial	2011-IND-0650	Other	11,311.42	15,834
102	Total M2 South Industrial			6,325,010.96	2,413,240
103	M4 South Industrial	2011-IND-0587	Other	738,217.24	264,201
104	M4 South Industrial	2011-IND-0556	Other	83,960.05	186,152
105	M4 South Industrial	2011-IND-0554	Other	82,141.73	173,984
106	M4 South Industrial	2011-IND-0345	Other	109,981.11	118,835
107	M4 South Industrial	2011-IND-0208	Controls	172,720.47	58,175
108	M4 South Industrial	2011-IND-0332	Other	18,325.30	85,821
109	M4 South Industrial	2011-IND-0652	Other	47,696.86	59,376
110	M4 South Industrial	2011-IND-0402	Other	27,411.57	39,584
111	M4 South Industrial	2011-IND-0435	Other	21,494.63	27,709
112	M4 South Industrial	2011-IND-0362	Heat Recovery System	128,289.55	44,725

113	M4 South Industrial	2011-IND-0227	Controls	17,952.00	7,314
114	M4 South Industrial	2011-IND-0228	Steam Distribution System	6,422.60	1,697
115	M4 South Industrial	2011-IND-0288	Controls	17,572.08	7,786
116	M4 South Industrial	2011-IND-0361	Controls	11,595.07	7,397
117	M4 South Industrial	2011-IND-0598	Heat Recovery System	171,250.68	39,380
118	M4 South Industrial	2011-IND-0580	Heat Recovery System	1,052,996.50	46,285
119	M4 South Industrial	2011-IND-0297	Other	350,195.00	136,597
120	M4 South Industrial	2011-IND-0109	Controls	179,263.52	36,912
121	M4 South Industrial	2011-IND-0501	Other	50,153.40	22,923
122	M4 South Industrial	2011-IND-0344	Heat Recovery System	75,887.44	26,120
123	M4 South Industrial	2011-IND-0599	Steam Distribution System	176,042.62	103,944
124	M4 South Industrial	2011-IND-0389	Controls	1,131,040.67	449,805
125	M4 South Industrial	2011-IND-0023	Insulation	40,798.14	15,572
126	M4 South Industrial	2011-IND-0472	Burners	751,273.95	275,658
127	M4 South Industrial	2011-IND-0544	Heat Recovery System	41,478.39	22,696
128	M4 South Industrial	2011-IND-0595	Other	302,198.09	148,493
129	M4 South Industrial	2011-IND-0506	Controls	587,261.57	198,446
130	M4 South Industrial	2011-IND-0299	Heat Recovery System	86,239.23	34,630
131	M4 South Industrial	2011-IND-0210	Heat Recovery System	141,210.50	49,195
132	M4 South Industrial	2011-IND-0009	Insulation	141,496.61	49,321
133	M4 South Industrial	2011-IND-0126	Controls	16,348.44	5,683
134	M4 South Industrial	2011-IND-0298	Heat Recovery System	39,510.34	14,522
135	M4 South Industrial	2011-IND-0484	Other	28,594.84	16,041
136	M4 South Industrial	2011-IND-0189	Controls	1,669,676.93	467,005
137	M4 South Industrial	2011-IND-0247	Insulation	61,537.60	27,831
138	M4 South Industrial	2011-IND-0025	Heat Recovery System	484,164.46	140,339
139	M4 South Industrial	2011-IND-0022	Heat Recovery System	88,159.84	31,133
140	M4 South Industrial	2011-IND-0223	Building Automation Systems	243,452.67	67,385
141	M4 South Industrial	2011-IND-0286	Boiler - Steam	79,482.60	20,969
142	M4 South Industrial	2011-IND-0239	Other	738,966.86	128,630
143	M4 South Industrial	2011-IND-0558	Make Up Air	2,648,677.66	173,310
144	M4 South Industrial	2011-IND-0151	HVAC Units	31,938.97	6,027
145	M4 South Industrial	2011-IND-0134	Steam Distribution System	188,177.40	103,286
146	M4 South Industrial	2011-IND-0024	Steam Distribution System	4,362.59	2,823
147	M4 South Industrial	2011-IND-0035	Heat Recovery System	215,804.96	61,811
148	M4 South Industrial	2011-IND-0019	Heat Recovery System	77,470.84	26,587
149	M4 South Industrial	2011-IND-0477	Insulation	535,091.81	185,605
150	M4 South Industrial	2011-IND-0099	Steam Distribution System	104,046.81	63,027
151	M4 South Industrial	2011-IND-0399	Heat Recovery System	134,805.89	31,737
152	M4 South Industrial	2011-IND-0251	Boiler - Steam	25,993.35	52,590
153	M4 South Industrial	2011-IND-0015	Other	81,896.02	36,705
154	M4 South Industrial	2011-IND-0212	Insulation	106,691.29	40,260
155	M4 South Industrial	2011-IND-0582	Boiler - Steam	1,050,175.44	423,865
156	M4 South Industrial	2011-IND-0624	Other	320,652.72	132,000
157	M4 South Industrial	2011-IND-0341	Make Up Air	386,751.70	101,972
158	M4 South Industrial	2011-IND-0101	Other	61,370.82	24,969
159	M4 South Industrial	2011-IND-0036	Heat Recovery System	169,041.73	100,902
160	M4 South Industrial	2011-IND-0372	Heat Recovery System	40,850.38	15,501
161	M4 South Industrial	2011-IND-0211	Steam Distribution System	12,659.29	8,307
162	M4 South Industrial	2011-IND-0285	Other	78,377.13	27,018
163	M4 South Industrial	2011-IND-0149	HVAC Units	27,658.45	5,054
164	M4 South Industrial	2011-IND-0343	Heat Recovery System	103,916.10	40,340
165	M4 South Industrial	2011-IND-0429	Other	17,789.32	33,768
166	M4 South Industrial	2011-IND-0089	Other	61,370.82	24,969
167	M4 South Industrial	2011-IND-0150	HVAC Units	82,939.99	4,578
168	M4 South Industrial	2011-IND-0159	Boiler - Hot Water	59,489.71	43,675
169	M4 South Industrial	2011-IND-0182	Steam Distribution System	21,762.19	15,665
170	M4 South Industrial	2011-IND-0309	Other	40,823.41	15,255
171	M4 South Industrial	2011-IND-0033	Steam Distribution System	1,425,900.06	856,462
172	M4 South Industrial	2011-IND-0329	Insulation	90,229.01	32,512
173	M4 South Industrial	2011-IND-0525	HVAC Units	60,258.27	20,170
174	M4 South Industrial	2011-IND-0546	Make Up Air	37,767.89	12,536
175	M4 South Industrial	2011-IND-0287	Steam Distribution System	944,212.28	535,957

176	M4 South Industrial	2011-IND-0322	Boiler - Steam	5,014.56	103,754
177	M4 South Industrial	2011-IND-0524	Steam Distribution System	35,171.86	19,304
178	M4 South Industrial	2011-IND-0522	Boiler - Steam	337,219.36	114,707
179	M4 South Industrial	2011-IND-0547	Make Up Air	26,264.59	8,956
180	M4 South Industrial	2011-IND-0434	Heat Recovery System	51,721.87	14,634
181	M4 South Industrial	2011-IND-0447	Other	175,059.30	90,851
182	M4 South Industrial	2011-IND-0014	Insulation	126,167.97	64,325
183	M4 South Industrial	2011-IND-0420	Other	273,004.45	104,344
184	M4 South Industrial	2011-IND-0594	Steam Distribution System	393,171.92	230,370
185	M4 South Industrial	2011-IND-0334	Insulation	43,851.52	23,362
186	M4 South Industrial	2011-IND-0376	Other	61,194.89	15,968
187	M4 South Industrial	2011-IND-0545	Make Up Air	109,848.32	35,182
188	M4 South Industrial	2011-IND-0419	Other	13,738.72	12,164
189	M4 South Industrial	2011-IND-0357	Steam Distribution System	19,288.92	6,198
190	Total M4 South Industrial			21,132,133.72	7,761,632
191	M5 South Industrial	2011-IND-0400	Other	21,260.03	27,709
192	M5 South Industrial	2011-IND-0257	Heat Recovery System	137,441.06	122,360
193	M5 South Industrial	2011-IND-0421	Heat Recovery System	2,601.89	25,686
194	M5 South Industrial	2011-IND-0601	Heat Recovery System	211,095.72	92,885
195	M5 South Industrial	2011-IND-0644	Other	107,472.81	622,830
196	M5 South Industrial	2011-IND-0280	Controls	663,549.06	237,314
197	M5 South Industrial	2011-IND-0209	Controls	184,145.28	73,408
198	M5 South Industrial	2011-IND-0190	Other	70,674.61	77,883
199	M5 South Industrial	2011-IND-0222	Controls	98,985.41	40,296
200	M5 South Industrial	2011-IND-0403	Other	29,415.33	39,584
201	M5 South Industrial	2011-IND-0049	Other	92,276.69	67,536
202	M5 South Industrial	2011-IND-0124	Other	213,995.94	141,639
203	M5 South Industrial	2011-IND-0449	Controls	215,718.95	37,838
204	M5 South Industrial	2011-IND-0513	Heat Recovery System	165,107.44	65,148
205	M5 South Industrial	2011-IND-0116	Other	26,693.50	31,073
206	M5 South Industrial	2011-IND-0647	Other	44,810.87	207,054
207	M5 South Industrial	2011-IND-0436	Other	371,252.47	146,004
208	M5 South Industrial	2011-IND-0405	Other	30,422.47	39,584
209	M5 South Industrial	2011-IND-0256	Other	2,991.07	3,958
210	M5 South Industrial	2011-IND-0480	Other	18,332.30	23,750
211	M5 South Industrial	2011-IND-0323	Heat Recovery System	48,233.45	228,557
212	M5 South Industrial	2011-IND-0265	Heat Recovery System	150,405.55	139,197
213	M5 South Industrial	2011-IND-0240	Controls	245,277.17	82,797
214	M5 South Industrial	2011-IND-0635	Other	54,815.00	242,732
215	M5 South Industrial	2011-IND-0180	Insulation	21,858.08	27,524
216	M5 South Industrial	2011-IND-0437	Other	143,804.22	123,874
217	M5 South Industrial	2011-IND-0008	Other	30,963.51	40,792
218	M5 South Industrial	2011-IND-0640	Other	66,673.34	316,540
219	M5 South Industrial	2011-IND-0424	Other	29,315.07	35,625
220	M5 South Industrial	2011-IND-0657	Other	61,114.47	297,917
221	M5 South Industrial	2011-IND-0215	Controls	41,642.14	12,857
222	M5 South Industrial	2011-IND-0384	Other	82,594.43	368,201
223	M5 South Industrial	2011-IND-0162	Heat Recovery System	158,463.40	69,687
224	M5 South Industrial	2011-IND-0406	Other	5,870.65	7,917
225	M5 South Industrial	2011-IND-0218	Other	44,472.23	55,417
226	M5 South Industrial	2011-IND-0448	Other	99,363.36	130,626
227	M5 South Industrial	2011-IND-0528	Other	19,091.30	23,750
228	M5 South Industrial	2011-IND-0476	Other	29,950.08	39,584
229	M5 South Industrial	2011-IND-0433	Controls	838,669.23	298,948
230	M5 South Industrial	2011-IND-0217	Other	63,383.43	79,168
231	M5 South Industrial	2011-IND-0179	Insulation	174,124.29	103,713
232	M5 South Industrial	2011-IND-0478	Other	58,401.31	77,584
233	M5 South Industrial	2011-IND-0011	Other	57,920.64	72,307
234	M5 South Industrial	2011-IND-0108	Other	3,732.69	4,492
235	M5 South Industrial	2011-IND-0369	Other	3,261.69	3,958
236	M5 South Industrial	2011-IND-0055	Other	189,085.88	21,712
237	M5 South Industrial	2011-IND-0485	Other	17,544.32	23,750

238	M5 South Industrial	2011-IND-0370	Other	6,346.06	7,917
239	M5 South Industrial	2011-IND-0054	Other	39,218.34	49,560
240	M5 South Industrial	2011-IND-0021	Other	25,788.78	32,828
241	M5 South Industrial	2011-IND-0643	Other	66,666.93	337,771
242	M5 South Industrial	2011-IND-0088	Insulation	3,360.98	1,425
243	M5 South Industrial	2011-IND-0649	Other	7,501.87	11,875
244	M5 South Industrial	2011-IND-0431	Other	31,354.23	39,584
245	M5 South Industrial	2011-IND-0678	Heat Recovery System	634,014.54	313,977
246	M5 South Industrial	2011-IND-0401	Other	4,259.57	24,618
247	M5 South Industrial	2011-IND-0422	Other	27,543.71	35,625
248	M5 South Industrial	2011-IND-0423	Other	5,148.42	43,182
249	M5 South Industrial	2011-IND-0442	Controls	48,120.22	15,468
250	M5 South Industrial	2011-IND-0651	Other	12,340.21	15,834
251	M5 South Industrial	2011-IND-0003	Heat Recovery System	189,104.72	72,039
252	M5 South Industrial	2011-IND-0504	Controls	140,130.88	65,148
253	M5 South Industrial	2011-IND-0634	Other	53,381.26	245,273
254	M5 South Industrial	2011-IND-0259	Steam Distribution System	160,309.73	96,417
255	M5 South Industrial	2011-IND-0081	Insulation	79,866.09	28,820
256	M5 South Industrial	2011-IND-0488	Steam Distribution System	68,463.53	42,481
257	M5 South Industrial	2011-IND-0507	Heat Recovery System	7,643.69	3,752
258	M5 South Industrial	2011-IND-0100	Steam Distribution System	293,285.12	174,063
259	M5 South Industrial	2011-IND-0097	Steam Distribution System	211,746.02	127,757
260	M5 South Industrial	2011-IND-0290	Heat Recovery System	527,893.73	229,883
261	M5 South Industrial	2011-IND-0498	Insulation	55,849.62	39,535
262	M5 South Industrial	2011-IND-0219	Heat Recovery System	280,245.01	116,437
263	M5 South Industrial	2011-IND-0079	Insulation	32,977.76	12,167
264	M5 South Industrial	2011-IND-0295	Steam Distribution System	11,763.29	5,641
265	M5 South Industrial	2011-IND-0026	Controls	22,986,175.06	3,556,786
266	M5 South Industrial	2011-IND-0521	Insulation	78,877.12	39,834
267	M5 South Industrial	2011-IND-0090	Steam Distribution System	56,489.11	33,938
268	M5 South Industrial	2011-IND-0157	Steam Distribution System	36,037.37	23,833
269	M5 South Industrial	2011-IND-0548	Steam Distribution System	242,556.50	142,627
270	M5 South Industrial	2011-IND-0146	Heat Recovery System	43,570.58	32,359
271	M5 South Industrial	2011-IND-0439	Insulation	60,931.33	26,009
272	M5 South Industrial	2011-IND-0293	Steam Distribution System	8,754.51	4,068
273	M5 South Industrial	2011-IND-0216	Heat Recovery System	3,995,184.49	1,300,982
274	M5 South Industrial	2011-IND-0385	Other	326,256.46	150,828
275	M5 South Industrial	2011-IND-0327	Insulation	31,736.17	14,149
276	M5 South Industrial	2011-IND-0339	Heat Recovery System	629,233.11	229,883
277	M5 South Industrial	2011-IND-0266	Insulation	100,470.97	61,791
278	M5 South Industrial	2011-IND-0518	HVAC Units	400,508.02	73,570
279	M5 South Industrial	2011-IND-0292	Steam Distribution System	61,685.51	23,900
280	M5 South Industrial	2011-IND-0479	Insulation	26,594.73	8,767
281	M5 South Industrial	2011-IND-0518	Insulation	36,691.91	20,942
282	M5 South Industrial	2011-IND-0241	Insulation	252,378.36	114,248
283	M5 South Industrial	2011-IND-0305	Other	6,309.48	29,919
284	M5 South Industrial	2011-IND-0048	Other	263,480.93	108,371
285	M5 South Industrial	2011-IND-0425	Other	699,230.02	272,206
286	M5 South Industrial	2011-IND-0347	Steam Distribution System	77,796.93	18,846
287	M5 South Industrial	2011-IND-0363	Insulation	68,622.04	24,631
288	M5 South Industrial	2011-IND-0444	Steam Distribution System	5,871.85	2,546
289	M5 South Industrial	2011-IND-0296	Steam Distribution System	10,511.96	4,475
290	M5 South Industrial	2011-IND-0463	Other	518,430.49	181,453
291	M5 South Industrial	2011-IND-0145	Other	105,436.44	50,476
292	M5 South Industrial	2011-IND-0156	Insulation	129,888.73	44,762
293	M5 South Industrial	2011-IND-0529	Make Up Air	409,868.71	57,166
294	M5 South Industrial	2011-IND-0438	Other	14,479.42	6,910
295	M5 South Industrial	2011-IND-0181	Insulation	96,757.46	60,257
296	M5 South Industrial	2011-IND-0020	Heat Recovery System	68,287.69	25,384
297	M5 South Industrial	2011-IND-0555	Other	31,392.76	18,588
298	M5 South Industrial	2011-IND-0520	Steam Distribution System	134,757.43	78,998
299	M5 South Industrial	2011-IND-0252	Other	27,293.92	15,563
300	M5 South Industrial	2011-IND-0553	Controls	76,206.96	40,747

301	M5 South Industrial	2011-IND-0294	Steam Distribution System	65,151.44	24,138
302	M5 South Industrial	2011-IND-0062	Insulation	103,748.91	64,377
303	M5 South Industrial	2011-IND-0386	Steam Distribution System	9,394.59	6,159
304	M5 South Industrial	2011-IND-0052	Other	39,351.95	17,350
305	M5 South Industrial	2011-IND-0517	Controls	165,054.95	44,032
306	M5 South Industrial	2011-IND-0380	Controls	27,604.69	15,511
307	M5 South Industrial	2011-IND-0380	Controls	11,206.72	3,570
308	M5 South Industrial	2011-IND-0380	Heat Recovery System	230,126.96	87,195
309	Total M5 South Industrial			41,242,992.85	14,403,985
310	M7 South Industrial	2011-IND-0121	Insulation	1,594,662.31	684,200
311	M7 South Industrial	2011-IND-0080	Steam Distribution System	76,000.11	51,350
312	M7 South Industrial	2011-IND-0204	Insulation	32,237.63	12,460
313	M7 South Industrial	2011-IND-0579	Steam Distribution System	1,203,352.30	776,336
314	M7 South Industrial	2011-IND-0042	Gas Turbine	64,786.49	191,043
315	M7 South Industrial	2011-IND-0165	Steam Distribution System	3,560,511.22	2,203,425
316	M7 South Industrial	2011-IND-0516	Make Up Air	1,541,700.55	939,071
317	M7 South Industrial	2011-IND-0013	Controls	124,028.98	43,104
318	M7 South Industrial	2011-IND-0440	Other	489,602.37	98,017
319	M7 South Industrial	2011-IND-0164	Steam Distribution System	1,420,582.08	879,087
320	M7 South Industrial	2011-IND-0037	Insulation	1,324,214.78	440,586
321	M7 South Industrial	2011-IND-0497	Heat Recovery System	175,718.95	429,935
322	M7 South Industrial	2011-IND-0514	Steam Distribution System	1,284,175.37	783,168
323	M7 South Industrial	2011-IND-0527	Steam Distribution System	18,022.05	9,618
324	M7 South Industrial	2011-IND-0282	Steam Distribution System	1,878,010.21	602,026
325	M7 South Industrial	2011-IND-0593	Steam Distribution System	397,778.89	240,145
326	M7 South Industrial	2011-IND-0515	Steam Distribution System	2,047,735.68	658,147
327	M7 South Industrial	2011-IND-0007	Steam Distribution System	74,193.19	35,323
328	M7 South Industrial	2011-IND-0221	Steam Distribution System	582,663.55	133,291
329	M7 South Industrial	2011-IND-0010	Insulation	22,739.01	22,801
330	M7 South Industrial	2011-IND-0500	Other	183,975.19	49,114
331	M7 South Industrial	2011-IND-0418	Controls	1,844,161.80	602,055
332	M7 South Industrial	2011-IND-0500	Steam Distribution System	94,887.53	55,550
333	M7 South Industrial	2011-IND-0441	Other	887,304.03	383,478
334	M7 South Industrial	2011-IND-0397	Other	1,517.81	10,170
335	M7 South Industrial	2011-IND-0281	Steam Distribution System	528,732.76	315,370
336	M7 South Industrial	2011-IND-0012	Other	1,679,164.45	566,297
337	M7 South Industrial	2011-IND-0633	Steam Distribution System	2,203,228.96	1,421,380
338	M7 South Industrial	2011-IND-0510	Insulation	356,562.41	143,016
339	Total M7 South Industrial			25,692,250.66	12,779,564
340	T1 South Industrial	2011-IND-0404	Other	58,863.81	79,168
341	T1 South Industrial	2011-IND-0543	Other	444,014.42	747,776
342	T1 South Industrial	2011-IND-0016	Other	26,103.42	32,431
343	T1 South Industrial	2011-IND-0214	Other	18,094.94	23,750
344	T1 South Industrial	2011-IND-0137	Other	67,591.97	83,365
345	T1 South Industrial	2011-IND-0141	Other	77,504.65	50,503
346	T1 South Industrial	2011-IND-0508	Other	108,139.22	142,502
347	T1 South Industrial	2011-IND-0142	Heat Recovery System	7,212.74	63,575
348	T1 South Industrial	2011-IND-0107	Other	256,975.63	307,021
349	T1 South Industrial	2011-IND-0641	Other	245,045.35	419,718
350	T1 South Industrial	2011-IND-0277	Insulation	275,928.74	130,253
351	T1 South Industrial	2011-IND-0559	Controls	1,006,891.15	343,386
352	T1 South Industrial	2011-IND-0519	Heat Recovery System	153,471.51	69,922
353	T1 South Industrial	2011-IND-0245	Make Up Air	76,242.28	48,458
354	T1 South Industrial	2011-IND-0276	Steam Distribution System	901,335.03	260,915
355	T1 South Industrial	2011-IND-0248	Steam Distribution System	41,291.91	26,224
356	T1 South Industrial	2011-IND-0336	Other	35,786.25	33,810
357	T1 South Industrial	2011-IND-0502	Other	117,412.05	197,825
358	T1 South Industrial	2011-IND-0666	Heat Recovery System	561,485.65	178,716
359	T1 South Industrial	2011-IND-0321	Steam Distribution System	106,389.08	61,315
360	T1 South Industrial	2011-IND-0047	Heat Recovery System	50,423.71	22,093
361	T1 South Industrial	2011-IND-0670	Heat Recovery System	340,848.79	128,816

362	T1 South Industrial	2011-IND-0662	Steam Distribution System	52,276.72	32,596
363	T1 South Industrial	2011-IND-0244	Steam Distribution System	81,555.57	20,446
364	T1 South Industrial	2011-IND-0605	Boiler - Steam	48,997.15	19,711
365	T1 South Industrial	2011-IND-0001	HVAC Units	1,293,543.66	396,387
366	T1 South Industrial	2011-IND-0620	Other	66,634.75	26,307
367	T1 South Industrial	2011-IND-0018	Laundry	309,020.12	160,453
368	T1 South Industrial	2011-IND-0069	Controls	1,129,247.34	387,734
369	T1 South Industrial	2011-IND-0342	Controls	214,869.38	66,358
370	T1 South Industrial	2011-IND-0658	Steam Distribution System	66,112.93	55,051
371	T1 South Industrial	2011-IND-0622	Other	6,891.62	3,360
372	T1 South Industrial	2011-IND-0675	Insulation	78,248.15	40,770
373	T1 South Industrial	2011-IND-0084	Heat Recovery System	49,138.07	26,360
374	T1 South Industrial	2011-IND-0483	Other	107,088.07	36,904
375	T1 South Industrial	2011-IND-0676	Controls	248,571.45	76,253
376	T1 South Industrial	2011-IND-0654	Insulation	4,928.07	4,898
377	T1 South Industrial	2011-IND-0346	Burners	28,533.50	17,498
378	T1 South Industrial	2011-IND-0387	Other	425,814.02	112,719
379	T1 South Industrial	2011-IND-0171	Steam Distribution System	334,895.61	205,744
380	T1 South Industrial	2011-IND-0646	Heat Recovery System	421,584.08	237,899
381	T1 South Industrial	2011-IND-0224	Make Up Air	213,349.69	164,384
382	T1 South Industrial	2011-IND-0665	Controls	779,294.09	290,172
383	T1 South Industrial	2011-IND-0665	Controls	569,497.55	228,950
384	T1 South Industrial	2011-IND-0665	Insulation	167,557.58	95,634
385	T1 South Industrial	2011-IND-0665	HVAC Units	108,697.92	21,492
386	T1 South Industrial	2011-IND-0665	Controls	15,132.45	13,648
387	T1 South Industrial	2011-IND-0665	HVAC Units	123,639.91	11,986
388	T1 South Industrial	2011-IND-0665	Other	8,015.64	5,713
389	T1 South Industrial	2011-IND-0591	Heat-Treat Furnace - Radiant Tube	451,927.15	200,566
390	T1 South Industrial	2011-IND-0481	Other	48,670.83	16,745
391	T1 South Industrial	2011-IND-0645	Heat Recovery System	421,135.40	237,747
392	T1 South Industrial	2011-IND-0243	Insulation	111,317.27	44,589
393	T1 South Industrial	2011-IND-0238	Insulation	1,728,611.45	604,096
394	T1 South Industrial	2011-IND-0430	Steam Distribution System	648,684.60	396,735
395	T1 South Industrial	2011-IND-0249	Steam Distribution System	828,989.42	516,719
396	T1 South Industrial	2011-IND-0482	Other	508,313.47	174,018
397	T1 South Industrial	2011-IND-0226	Other	184,048.62	58,648
398	T1 South Industrial	2011-IND-0340	Insulation	135,015.07	47,849
399	T1 South Industrial	2011-IND-0661	Heat Recovery System	37,175.99	19,338
400	T1 South Industrial	2011-IND-0679	Insulation	10,963.58	18,319
401	T1 South Industrial	2011-IND-0065	Heat Recovery System	477,963.68	176,312
402	T1 South Industrial	2011-IND-0619	Steam Distribution System	175,002.34	109,296
403	T1 South Industrial	2011-IND-0674	Heat Recovery System	250,471.10	98,344
404	T1 South Industrial	2011-IND-0673	Boiler - Steam	4,927.88	4,955
405	T1 South Industrial	2011-IND-0246	Make Up Air	70,527.24	48,458
406	T1 South Industrial	2011-IND-0592	Other	411,913.99	151,331
407	T1 South Industrial	2011-IND-0005	Heat Recovery System	117,519.38	42,983
408	T1 South Industrial	2011-IND-0163	Steam Distribution System	22,778.30	13,413
409	T1 South Industrial	2011-IND-0161	Steam Distribution System	343,821.87	166,299
410	T1 South Industrial	2011-IND-0394	Insulation	1,699.32	937
411	T1 South Industrial	2011-IND-0388	Insulation	7,133.10	12,955
412	T1 South Industrial	2011-IND-0213	Insulation	435,946.47	147,954
413	T1 South Industrial	2011-IND-0417	Steam Distribution System	1,261,324.09	687,741
414	T1 South Industrial	2011-IND-0375	Other	961,596.23	366,859
415	T1 South Industrial	2011-IND-0487	Other	291,678.90	649,176
416	T1 South Industrial	2011-IND-0275	Heat Recovery System	1,768,456.56	2,847,323
417	T1 South Industrial	2011-IND-0044	Heat Recovery System	423,090.51	104,283
418	T1 South Industrial	2011-IND-0135	Other	4,960,582.97	1,540,996
419	T1 South Industrial	2011-IND-0475	Steam Distribution System	391,376.14	226,929
420	T1 South Industrial	2011-IND-0220	Steam Distribution System	129,694.06	63,415
421	T1 South Industrial	2011-IND-0398	Other	2,927,252.16	1,139,610
422	T1 South Industrial	2011-IND-0486	Other	150,994.06	585,985
423	T1 South Industrial	2011-IND-0469	Steam Distribution System	284,467.27	94,570
424	T1 South Industrial	2011-IND-0616	Burners	970,988.65	435,169

425	T1 South Industrial	2011-IND-0058	Steam Distribution System	208,154.64	120,369
426	T1 South Industrial	2011-IND-0046	Steam Distribution System	570,226.71	326,284
427	T1 South Industrial	2011-IND-0106	Steam Distribution System	498,579.27	224,316
428	T1 South Industrial	2011-IND-0184	Convection Oven - Curing/Drying	796,058.15	297,063
429	T1 South Industrial	2011-IND-0326	Heat Recovery System	1,370,589.90	3,398,868
430	T1 South Industrial	2011-IND-0416	Other	499,649.87	2,044,682
431	T1 South Industrial	2011-IND-0569	Steam Distribution System	3,344,745.68	1,061,255
432	T1 South Industrial	2011-IND-0147	Other	392,958.90	86,483
433	T1 South Industrial	2011-IND-0315	Refinery Heater/Reformer	1,692,598.37	571,763
434	T1 South Industrial	2011-IND-0632	Other	2,244,423.75	983,356
435	T1 South Industrial	2011-IND-0468	Refinery Heater/Reformer	4,007,630.04	1,351,729
436	T1 South Industrial	2011-IND-0415	Steam Distribution System	1,940,125.12	1,055,265
437	T1 South Industrial	2011-IND-0104	Steam Distribution System	1,711,548.53	976,255
438	T1 South Industrial	2011-IND-0368	Other	158,434.20	102,315
439	T1 South Industrial	2011-IND-0191	Steam Distribution System	2,368,428.66	759,958
440	T1 South Industrial	2011-IND-0427	Heat-Treat Furnace - Radiant Tube	371,181.32	132,111
441	T1 South Industrial	2011-IND-0374	Other	961,596.23	366,859
442	T1 South Industrial	2011-IND-0564	Steam Distribution System	3,929,848.91	1,224,929
443	T1 South Industrial	2011-IND-0045	Insulation	17,943.09	6,352
444	T1 South Industrial	2011-IND-0596	Steam Distribution System	280,924.86	125,660
445	T1 South Industrial	2011-IND-0493	Heat Recovery System	553,068.35	217,421
446	T1 South Industrial	2011-IND-0584	Controls	839,374.90	412,752
447	T1 South Industrial	2011-IND-0656	Heat Recovery System	761,776.28	1,258,985
448	T1 South Industrial	2011-IND-0648	Steam Distribution System	102,508.46	34,025
449	T1 South Industrial	2011-IND-0308	Other	4,122,230.50	1,385,996
450	T1 South Industrial	2011-IND-0258	Heat Recovery System	706,652.61	247,428
451	T1 South Industrial	2011-IND-0250	Other	33,555.47	14,459
452	T1 South Industrial	2011-IND-0607	Steam Distribution System	38,166.38	11,866
453	T1 South Industrial	2011-IND-0187	Steam Distribution System	1,390,882.48	438,906
454	T1 South Industrial	2011-IND-0557	Reheat Furnace	4,316,795.55	1,474,685
455	T1 South Industrial	2011-IND-0668	HVAC Units	490,798.35	187,484
456	T1 South Industrial	2011-IND-0588	Refinery Heater/Reformer	647,991.48	202,509
457	T1 South Industrial	2011-IND-0289	Heat Recovery System	1,505,075.26	525,056
458	T1 South Industrial	2011-IND-0185	Steam Distribution System	9,951,589.92	5,600,079
459	T1 South Industrial	2011-IND-0378	Heat-Treat Furnace - Radiant Tube	573,231.03	193,269
460	T1 South Industrial	2011-IND-0589	Other	553,664.84	268,021
461	T1 South Industrial	2011-IND-0590	Steam Distribution System	568,799.48	337,241
462	T1 South Industrial	2011-IND-0567	Burners	2,487,339.71	863,283
463	T1 South Industrial	2011-IND-0573	Steam Distribution System	1,511,423.21	872,545
464	T1 South Industrial	2011-IND-0604	Controls	51,281.31	17,503
465	T1 South Industrial	2011-IND-0655	Heat Recovery System	2,224,958.44	1,143,789
466	T1 South Industrial	2011-IND-0474	Other	224,110.16	74,306
467	T1 South Industrial	2011-IND-0043	Other	50,260.83	10,585
468	T1 South Industrial	2011-IND-0193	Steam Distribution System	2,526,708.11	1,458,547
469	T1 South Industrial	2011-IND-0140	Steam Distribution System	61,767.25	25,022
470	T1 South Industrial	2011-IND-0123	Other	23,728.61	162
471	T1 South Industrial	2011-IND-0669	Other	893,741.49	314,490
472	T1 South Industrial	2011-IND-0460	Steam Distribution System	1,031,337.77	612,042
473	T1 South Industrial	2011-IND-0461	Steam Distribution System	1,338,744.54	794,023
474	T1 South Industrial	2011-IND-0494	Heat Recovery System	884,613.43	315,368
475	T1 South Industrial	2011-IND-0470	Controls	1,069,195.47	375,307
476	T1 South Industrial	2011-IND-0337	Other	690,950.60	234,034
477	T1 South Industrial	2011-IND-0316	Refinery Heater/Reformer	977,671.41	330,224
478	T1 South Industrial	2011-IND-0313	Refinery Heater/Reformer	4,077,753.24	1,375,934
479	T1 South Industrial	2011-IND-0192	Steam Distribution System	4,475,475.23	2,543,624
480	T1 South Industrial	2011-IND-0188	Steam Distribution System	2,773,343.85	1,572,706
481	T1 South Industrial	2011-IND-0312	Steam Distribution System	1,013,121.47	368,123
482	T1 South Industrial	2011-IND-0565	Steam Distribution System	3,740,938.14	1,592,167
483	T1 South Industrial	2011-IND-0105	Steam Distribution System	1,206,142.52	682,484
484	T1 South Industrial	2011-IND-0631	Other	2,244,423.75	983,356
485	T1 South Industrial	2011-IND-0503	Steam Distribution System	916,284.94	285,497
486	T1 South Industrial	2011-IND-0505	Steam Distribution System	220,841.88	124,070
487	T1 South Industrial	2011-IND-0186	Steam Distribution System	13,609,695.21	4,524,917

488	T1 South Industrial	2011-IND-0571	Other		2,108,470.10	1,020,646
489	T1 South Industrial	2011-IND-0358	Heat Recovery System		1,020,145.05	909,555
490	T1 South Industrial	2011-IND-0523	Other		258,008.76	116,171
491	T1 South Industrial	2011-IND-0667	Heat Recovery System		143,734.74	51,248
492	T1 South Industrial	2011-IND-0570	Steam Distribution System		2,640,698.78	1,521,812
493	T1 South Industrial	2011-IND-0338	Other		802,287.06	271,434
494	T1 South Industrial	2011-IND-0360	Heat Recovery System		2,574,409.54	894,140
495	T1 South Industrial	2011-IND-0318	Other		742,206.16	251,133
496	T1 South Industrial	2011-IND-0471	Controls		386,802.49	138,864
497	T1 South Industrial	2011-IND-0314	Refinery Heater/Reformer		2,634,051.48	892,925
498	T1 South Industrial	2011-IND-0491	Heat Recovery System		319,293.92	138,603
499	T1 South Industrial	2011-IND-0663	Heat Recovery System		864,884.82	301,762
500	T1 South Industrial	2011-IND-0183	Burners		2,542,128.58	864,531
501	T1 South Industrial	2011-IND-0572	Controls		1,644,790.27	859,245
502	T1 South Industrial	2011-IND-0671	Furnace		972,220.40	335,456
503	T1 South Industrial	2011-IND-0568	Heat Recovery System		203,886.66	231,935
504	T1 South Industrial	2011-IND-0560	Steam Distribution System		159,744.21	716,978
505	T1 South Industrial	2011-IND-0615	Steam Distribution System		1,297,604.71	720,196
506	T1 South Industrial	2011-IND-0512	Refinery Heater/Reformer		3,150,143.36	1,062,557
507	T1 South Industrial	2011-IND-0462	Other		6,901,724.30	2,371,184
508	T1 South Industrial	2011-IND-0459	Controls		139,366.29	43,798
509	T1 South Industrial	2011-IND-0664	Refinery Heater/Reformer		5,938,986.12	2,126,443
510	T1 South Industrial	2011-IND-0319	Other		256,478.26	87,367
511	T1 South Industrial	2011-IND-0317	Other		302,814.49	93,665
512	T1 South Industrial	2011-IND-0320	Other		201,897.09	68,667
513	T1 South Industrial	2011-IND-0203	Steam Distribution System		6,669,153.49	2,086,924
514	T1 South Industrial	2011-IND-0366	Other		1,058,177.05	362,746
515	T1 South Industrial	2011-IND-0311	Heat Recovery System		537,739.83	314,387
	Total T1 South Industrial				185,205,754.67	86,636,170
				Total	324,376,628.78	141,753,196

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 1 / Pages 12-13

Preamble: Union presented the following table in its evidence:

Table 2
2011 DSM Overspend

Line No.	Particulars ($000's)	2011 Plan	2011 Actual	Variance
1	Residential	3,139	2,699	(440)
2	Low-Income	1,903	1,729	(174)
3	Commercial	5,666	4,143	(1,523)
4	Distribution Contract	4,990	8,737	3,747
5	Market Transformation	1,464	1,572	108
6	Other Direct Program Costs	7,727	7,035	(692)
7	Subtotal	24,889	25,915	1,026
8	Incremental Low-Income	-	2,056	2,056
9	Total	24,889	27,971	3,082

a) On a line-by-line basis (Lines 1 – 6), please provide the rationale for all increases and decreases in DSM spending.

b) Please discuss any benefits that were achieved through the significant overspending in the Distribution Contract customer classification.

c) Please explain how Union goes about transferring spending amongst customer classifications? How does Union decide to which rate class additional spending should be directed?

d) Please provide a detailed analysis of the projects / programs which the additional $3.082 million in DSM spending helped to fund.

Response:

a) DSM spending on the Distribution Contract market (Line 6) was increased as this was identified as the most cost effective opportunity to influence m^3 savings in 2011. To accommodate this increased DSM spending and in recognition of reduced opportunities in Residential and Commercial markets, Lines 1, 3 and 4 were reduced.

b) The additional DSM spending of $3.7 million on the Distribution Contract customer projects resulted in a 39% increase or $91 million Net TRC savings increase over 2010 post audit results for the Distribution Contract customer classification. The number of custom project measures installed in 2011 by Distribution Contract customers also increased from 357 measures in 2010 to 1,125 measures in 2011. The greatest opportunity to influence DSM savings in 2011 was identified in the Distribution Contract market and the budget was allocated accordingly.

c) Spending on DSM programs is determined based on the customer demand for the programs and the opportunity to achieve m^3 savings.

d) In addition to the responses provided in 3 a) and 3 b) the Incremental Low-income DSM spend of $2.056 million for the Home Weatherization program contributed 514,599 m^3 of savings in 450 homes.

Union's additional DSM spending was spent on projects identified based on market opportunities. These projects are custom projects and can be found at Exhibit B1.2 Attachment 1.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 1 / Pages 15-17

Preamble: The evidence indicates that in accordance with previous Board-approved practice, Union is proposing to clear the recorded SSM balance related to unaudited 2011 DSM activities.

a) Please indicate when the audited balances will be available and filed with the Board.

b) Please confirm that the $0.544 million incentive claimed for the 2011 incremental low-income program has not been included in the total debit balance of $9.664 million in the SSM Variance Account.

c) Please confirm that the scorecard approach was only used to evaluate the incremental low-income DSM program approved on December 20, 2010 in EB-2010-0055 (and not the low-income programs approved on September 9, 2010 in EB-2010-0055).

Response:

a) Please see the response at Exhibit B1.2 a).

b) Confirmed.

c) Confirmed.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 1 / Page 18
Exhibit A / Tab 1 / Schedule 5

Please provide the calculation for determining the 2011 Board Approved Average Delivery Rates for each of the cited rate classes (at Line 11 of Exhibit A, Tab 1, Schedule 5).

Response:

Please see Attachment 1.

Derivation of 2011 Board-approved Average Delivery Rate for 2011 Average Use Deferral Calculations

Line No.	Particulars	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m) = sum (a to l)	(n)
	Rate 01														
1	Change in Average Use (m^3)	(37)	(2)	(24)	10	(14)	(8)	4	9	4	19	(20)	(1)	(61)	
2	2007 Board-approved Number of Customers	294,948	295,190	295,340	295,541	295,465	295,226	294,860	294,899	295,001	296,026	297,337	298,229	3,548,062	295,672
3	Volume Impact (10^3m^3)	(11,033)	(686)	(6,996)	2,912	(4,175)	(2,392)	1,228	2,557	1,106	5,703	(5,931)	(384)	(18,092)	
4	2011 Board-approved Delivery Rate ($/$10^3$m	70.42	70.42	70.42	70.82	70.82	70.82	71.00	71.00	71.00	70.76	70.76	70.76		
5	Average Use Deferral ($000's)	(777)	(48)	(493)	206	(296)	(169)	87	182	79	404	(420)	(27)	(1,273)	
6	Cumulative Volume Impact (10^3m^3)	(11,033)	(11,719)	(18,715)	(15,804)	(19,978)	(22,371)	(21,143)	(18,586)	(17,480)	(11,777)	(17,708)	(18,092)		
7	Cumulative Average Use Deferral ($000's)	(777)	(825)	(1,318)	(1,112)	(1,407)	(1,577)	(1,490)	(1,308)	(1,230)	(826)	(1,246)	(1,273)		
8	Cumulative Average Delivery Rate ($/$10^3m^3$)												**70.36** (2)		
	Rate 10														
9	Change in Average Use (m^3)	(4,783)	(2,460)	(538)	(3,536)	(638)	(1,559)	(241)	(344)	(201)	(2,675)	(2,204)	(1,413)	(20,591)	
10	2007 Board-approved Number of Customers	2,955	2,956	2,956	2,957	2,959	2,960	2,962	2,964	2,965	2,967	2,968	2,970	35,539	2,962
11	Volume Impact (10^3m^3)	(14,133)	(7,272)	(1,590)	(10,456)	(1,887)	(4,616)	(712)	(1,019)	(597)	(7,936)	(6,541)	(4,195)	(60,955)	
12	2011 Board-approved Delivery Rate ($/$10^3$m	46.33	46.33	46.33	46.52	46.52	46.52	46.60	46.60	46.60	46.49	46.49	46.49		
13	Average Use Deferral ($000's)	(655)	(337)	(74)	(486)	(88)	(215)	(33)	(47)	(28)	(369)	(304)	(195)	(2,831)	
14	Cumulative Volume Impact (10^3m^3)	(14,133)	(21,405)	(22,995)	(33,451)	(35,338)	(39,954)	(40,667)	(41,686)	(42,283)	(50,219)	(56,760)	(60,955)		
15	Cumulative Average Use Deferral ($000's)	(655)	(992)	(1,065)	(1,552)	(1,640)	(1,854)	(1,887)	(1,935)	(1,963)	(2,332)	(2,636)	(2,831)		
16	Cumulative Average Delivery Rate ($/$10^3m^3$)												**46.44** (4)		
	Rate M1/M2														
17	Change in Average Use (m^3)	(20)	(1)	15	42	10	(12)	(4)	7	10	1	(60)	(16)	(28)	
18	2007 Board-approved Number of Customers	981,740	983,166	984,582	985,182	985,576	985,348	985,337	983,264	987,482	990,967	994,944	997,164	11,844,752	987,063
19	Volume Impact (10^3m^3)	(19,764)	(1,397)	14,736	41,045	10,062	(12,108)	(3,612)	6,849	10,228	1,239	(59,992)	(15,781)	(28,496)	
20	2011 Board-approved Delivery Rate ($/$10^3$m	34.05	34.05	34.05	34.43	34.43	34.43	34.59	34.59	34.59	34.37	34.37	34.37		
21	Average Use Deferral ($000's)	(673)	(48)	502	1,413	346	(417)	(125)	237	354	43	(2,062)	(542)	(972)	
22	Cumulative Volume Impact (10^3m^3)	(19,764)	(21,161)	(6,425)	34,619	44,681	32,573	28,961	35,810	46,038	47,277	(12,714)	(28,496)		
23	Cumulative Average Use Deferral ($000's)	(673)	(721)	(219)	1,194	1,541	1,124	999	1,236	1,590	1,632	(430)	(972)		
24	Cumulative Average Delivery Rate ($/$10^3m^3$)												**34.11** (6)		

Notes:

(1) EB-2010-0148, Rate Order, Working Papers, Schedule 4, page 2, line 7, column (z), plus cumulative update to gas costs in delivery rates shown at Tab 2, Schedule 4, line 24, column (i) as per EB-2010-0359 (January 2011 QRAM), EB-2011-0029 (April 2011 QRAM), EB-2011-0135 (July 2011 QRAM) and EB-2011-0297 (October 2011 QRAM).

(2) Line 7, column (l) divided by line 6, column (l) multiplied by 1000.

(3) EB-2010-0148, Rate Order, Working Papers, Schedule 4, page 4, line 7, column (z), plus cumulative update to gas costs in delivery rates shown at Tab 2, Schedule 4, line 25, column (i) as per EB-2010-0359 (January 2011 QRAM), EB-2011-0029 (April 2011 QRAM), EB-2011-0135 (July 2011 QRAM) and EB-2011-0297 (October 2011 QRAM).

(4) Line 15, column (l) divided by line 14, column (l) multiplied by 1000.

(5) EB-2010-0148, Rate Order, Working Papers, Schedule 4, page 12, line 5 + line 13 column (y) divided by line 5 + line 13 column (x), plus cumulative update to gas costs in delivery rates shown at Tab 2, Schedule 4, line 11 and line 12, column (i) as per EB-2010-0359 (January 2011 QRAM), EB-2011-0029 (April 2011 QRAM), EB-2011-0135 (July 2011 QRAM) and EB-2011-0297 (October 2011 QRAM).

(6) Line 23, column (l) divided by line 22, column (l) multiplied by 1000.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 1 / Pages 20-22

Preamble: Union noted that the credit balance of $0.212 million recorded in the CDM deferral account represents 50% of the net revenues generated from two CDM programs.

Please provide a detailed breakdown of the revenues generated and cost incurred for each of the two CDM programs cited in the evidence.

Response:

The two CDM programs included in the CDM deferral account are:

1. The High Performance New Construction ("HPNC") program. Union was subcontracted through Enbridge to provide Sales Services in delivery of the OPA HPNC program in Union's service area. The Performance Bonus paid to Union by Enbridge to deliver the program resulted in net revenues of $0.250 million in 2010 and $0.172 million in 2011 of which 50% or 0.211 million is shared with rate payers. The amounts for 2010 and 2011 were mistakenly reversed in Union's evidence. The revenues and expenses can be broken down as follows:

   For HPNC – 2010 Activity, total revenues were $0.594 million and costs were $0.343 million, resulting in net revenues for sharing of $0.250 million.

   For HPNC – 2011 Activity, total revenues were $0.172 million. There were no costs as the program delivery ended at the end of 2010. Bonus payments from Enbridge continued in 2011.

2. The joint CDM/DSM Low Income pilot program in collaboration with Hydro One Networks Inc. delivered $1,404 in net revenue of which $702 is shared with ratepayers. Total revenue or cost recover invoiced to Hydro One Networks Inc. was $39,438 with costs of $29,756 for program incentives (showerheads etc) plus $8,278 for program implementation (marketing expense) resulting in a net revenue of $1,404 for this pilot program.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 1 / Pages 22-25

Preamble: Union noted that there is a credit balance of $0.662 million in the HST Deferral Account to be refunded to ratepayers.

a) Please confirm that the transactions recorded in the HST Deferral Account represent only the PST portion of the HST. If not, please update the schedule and recalculate the balance to be recorded in the account.

b) Please confirm that the transactions recorded in the HST Deferral Account represent only the regulated portion of the business. If not, please update the schedule and recalculate the balance to be recorded in the account.

Response:

a) Confirmed.

b) Confirmed.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 1 / Page 25

Preamble: Union indicated that the PST portion of HST on Union's own use of compressor fuel results in additional compressor costs to Union. Union stated that the increased compressor fuel cost to Union was $0.754 million in 2011 of which 50% (or $0.377 million) is attributable to ratepayers.

a) Please provide the calculation for the $0.754 million of increased compressor fuel costs.

b) Please provide a copy of the tax filing that Union will file (or has filed) for Restricted Income Tax Credit to the Canada Revenue Agency and reconcile the amount cited in the tax filing to the amount cited in the Application.

Response:

a)

Increased Compressor Fuel Costs

Particulars ($ millions)	2011
Own Use Compressor Fuel	
Total regulated	31.905
Customer Supplied Fuel	
Total regulated	22.482
Net Compressor Fuel cost	9.423
Restricted PST (8% of Net Compressor Fuel)	0.754

b) Please see Attachment 1 for the reconciliation to Union's Restricted Income Tax Credit. Please see Attachment 2 for the confirmation of inputs for Union's filings for Restricted Income Tax Credit for 2011.

UNION GAS LIMITED
Reconciliation of Restricted Input Tax Credits to the HST Deferral Account

Line No.	Particulars ($ millions)	2011 GST/HST Return RITC Line 1401
1	January	0.137
2	February	0.237
3	March	0.255
4	April	0.107
5	May	0.121
6	June	0.122
7	July	0.141
8	August	0.179
9	September	0.146
10	October	0.114
11	November	0.241
12	December	0.080
13		1.882
	Reconciliation	
	Capital	
14	Vehicle Purchases	0.342
	O&M	
15	Transportation Fuel	0.188
16	Hydro	0.315
17	Own Use Gas (Heating)	0.192
18	Other	0.020
19	Total O&M	0.715
20	Compressor Fuel Costs	0.754
21	Other	0.071
22		1.882

	Particulars ($ millions)	Savings	Additional Costs	Net Savings / (Cost)	Deferral Balance (50%)
23	Capital	0.838	(0.043) [(1)]	0.796	0.398
24	Operations and Maintenance	1.998	(0.715)	1.283	0.641
25	Compressor Fuel	-	(0.754)	(0.754)	(0.377)
26					0.662

Notes:

(1) The Capital Additional Costs is the revenue requirement impact of the HST remitted on Line 1401 of the GST/HST Return for both 2010 and 2011. 2011 Capital vehicle purchases of $0.342 million at line 14 are only one part of this.

Canada Revenue Agency / Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 966488.

Please print a copy of this confirmation for your records.

Thank you for using GST/HST NETFILE.

Business Number	119465367RT0001
Reporting period - From date	2011-01-01
Reporting period - To date	2011-01-31
Filing date	2011-02-28

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture)	$7,536,266.29

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-01-01 to 2011-01-31	$ 137,082.99	x 100%	$137,082.99

GST/HST Return Summary

Line 101 - Sales and other revenue	$264,095,527.77
Line 135 - Total GST/HST new housing rebates (included in line 108)	$0.00
Line 105 - Total GST/HST and adjustments for period	$36,775,298.59
Line 108 - Total ITCs and adjustments	$7,399,183.30
Line 109 - Net Tax	$29,376,115.29
Line 110 - Instalments and other annual filer payments	$0.00
Line 111 - Rebates (note: certain rebate forms must be mailed separately)	$0.00
Line 205 - GST/HST due on acquisition of taxable real property	$364,002.28
Line 405 - Other GST/HST to be self-assessed	$0.00
Line 114 - Refund claimed	$0.00
Amount owing	$29,740,117.57

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-01-25

Canada Revenue Agency / Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 214410.

Please print a copy of this confirmation for your records.

Thank you for using GST/HST NETFILE.

Business Number	119465367RT0001
Reporting period - From date	2011-02-01
Reporting period - To date	2011-02-28
Filing date	2011-03-31

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture) $7,452,866.38

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-02-01 to 2011-02-28	$ 237,336.05	x 100%	$237,336.05

GST/HST Return Summary

Line 101 - Sales and other revenue	$223,528,372.24
Line 135 - Total GST/HST new housing rebates (included in line 108)	$0.00
Line 105 - Total GST/HST and adjustments for period	$37,180,316.78
Line 108 - Total ITCs and adjustments	$7,215,530.33
Line 109 - Net Tax	$29,964,786.45
Line 110 - Instalments and other annual filer payments	$0.00
Line 111 - Rebates (note: certain rebate forms must be mailed separately)	$0.00
Line 205 - GST/HST due on acquisition of taxable real property	$1,950.00
Line 405 - Other GST/HST to be self-assessed	$0.00
Line 114 - Refund claimed	$0.00
Amount owing	$29,966,736.45

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-01-25

Canada Revenue Agency / Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 338639.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Number	119465367RT0001
Reporting period - From date	2011-03-01
Reporting period - To date	2011-03-31
Filing date	2011-04-29

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture)	8,608,818.38

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-03-01 to 2011-03-31	255,074.76	x 100%	255,074.76

Line 108 - Total ITCs and adjustments	8,353,743.62

GST/HST Return Summary

Line 101 - Sales and other revenue	214,497,101.68
Line 135 - Total GST/HST new housing rebates (included in line 108)	0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	0.00
Line 105 - Total GST/HST and adjustments for period	34,423,015.32
Line 108 - Total ITCs and adjustments	8,353,743.62
Line 109 - Net Tax	26,069,271.70
Line 110 - Instalments and other annual filer payments	0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	0.00
Line 205 - GST/HST due on acquisition of taxable real property	25,550.58
Line 405 - Other GST/HST to be self-assessed	0.00
Line 114 - Refund claimed	0.00
Amount owing	26,094,822.28

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-03-08

Canada Revenue Agency | Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 306838.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Number	119465367RT0001
Reporting period - From date	2011-04-01
Reporting period - To date	2011-04-30
Filing date	2011-05-31

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture)	9,492,038.76

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-04-01 to 2011-04-30	106,502.67	x 100%	106,502.67

Line 108 - Total ITCs and adjustments	9,385,536.09

GST/HST Return Summary

Line 101 - Sales and other revenue	159,033,848.53
Line 135 - Total GST/HST new housing rebates (included in line 108)	0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	0.00
Line 105 - Total GST/HST and adjustments for period	29,753,895.54
Line 108 - Total ITCs and adjustments	9,385,536.09
Line 109 - Net Tax	20,368,359.45
Line 110 - Instalments and other annual filer payments	0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	0.00
Line 205 - GST/HST due on acquisition of taxable real property	14,300.00
Line 405 - Other GST/HST to be self-assessed	0.00
Line 114 - Refund claimed	0.00
Amount owing	20,382,659.45

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-05-11

Canada Revenue Agency / Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 364788.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Number	119465367RT0001
Reporting period - From date	2011-05-01
Reporting period - To date	2011-05-31
Filing date	2011-06-30

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture) 8,989,447.78

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-05-01 to 2011-05-31	121,441.52	x 100%	121,441.52

Line 108 - Total ITCs and adjustments 8,868,006.26

GST/HST Return Summary

Line 101 - Sales and other revenue	116,172,826.81
Line 135 - Total GST/HST new housing rebates (included in line 108)	0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	0.00
Line 105 - Total GST/HST and adjustments for period	24,463,268.36
Line 108 - Total ITCs and adjustments	8,868,006.26
Line 109 - Net Tax	15,595,262.10
Line 110 - Instalments and other annual filer payments	0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	0.00
Line 205 - GST/HST due on acquisition of taxable real property	1.00
Line 405 - Other GST/HST to be self-assessed	0.00
Line 114 - Refund claimed	0.00
Amount owing	15,595,263.10

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-06-22

Canada Revenue Agency / Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 681067.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Number	119465367RT0001
Reporting period - From date	2011-06-01
Reporting period - To date	2011-06-30
Filing date	2011-07-22

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture)	8,771,376.73

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-06-01 to 2011-06-30	122,288.91	x 100%	122,288.91

Line 108 - Total ITCs and adjustments	8,649,087.82

GST/HST Return Summary

Line 101 - Sales and other revenue	96,862,298.05
Line 135 - Total GST/HST new housing rebates (included in line 108)	0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	0.00
Line 105 - Total GST/HST and adjustments for period	18,220,240.02
Line 108 - Total ITCs and adjustments	8,649,087.82
Line 109 - Net Tax	9,571,152.20
Line 110 - Instalments and other annual filer payments	0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	0.00
Line 205 - GST/HST due on acquisition of taxable real property	140,335.00
Line 405 - Other GST/HST to be self-assessed	0.00
Line 114 - Refund claimed	0.00
Amount owing	9,711,487.20

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-06-22

Canada Revenue Agency / Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 229436.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Number	119465367RT0001
Reporting period - From date	2011-07-01
Reporting period - To date	2011-07-31
Filing date	2011-08-26

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture)	$ 8,764,206.63

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-07-01 to 2011-07-31	$ 140,827.75	x 100%	$ 140,827.75

Line 108 - Total ITCs and adjustments	$ 8,623,378.88

GST/HST Return Summary

Line 101 - Sales and other revenue	$ 72,243,514.91
Line 135 - Total GST/HST new housing rebates (included in line 108)	$ 0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	$ 0.00
Line 105 - Total GST/HST and adjustments for period	$ 15,541,466.70
Line 108 - Total ITCs and adjustments	$ 8,623,378.88
Line 109 - Net Tax	$ 6,918,087.82
Line 110 - Instalments and other annual filer payments	$ 0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	$ 0.00
Line 205 - GST/HST due on acquisition of taxable real property	$ 0.00
Line 405 - Other GST/HST to be self-assessed	$ 0.00
Line 114 - Refund claimed	$ 0.00
Amount owing	$ 6,918,087.82

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-06-22

Canada Revenue Agency / Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 567419.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Number	119465367RT0001
Reporting period - From date	2011-08-01
Reporting period - To date	2011-08-31
Filing date	2011-09-30

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture) $ 9,555,408.24

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-08-01 to 2011-08-31	$ 179,402.44	x 100%	$ 179,402.44

Line 108 - Total ITCs and adjustments $ 9,376,005.80

GST/HST Return Summary

Line 101 - Sales and other revenue	$ 88,854,233.49
Line 135 - Total GST/HST new housing rebates (included in line 108)	$ 0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	$ 0.00
Line 105 - Total GST/HST and adjustments for period	$ 14,490,913.99
Line 108 - Total ITCs and adjustments	$ 9,376,005.80
Line 109 - Net Tax	$ 5,114,908.19
Line 110 - Instalments and other annual filer payments	$ 0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	$ 0.00
Line 205 - GST/HST due on acquisition of taxable real property	$ 7,800.00
Line 405 - Other GST/HST to be self-assessed	$ 0.00
Line 114 - Refund claimed	$ 0.00
Amount owing	$ 5,122,708.19

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-06-22

Canada Revenue Agency / Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 724066.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Name	UNION GAS LIMITED
Business Number	119465367RT0001
Reporting period - From date	2011-09-01
Reporting period - To date	2011-09-30
Filing date	2011-10-28

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture) $ 9,061,286.63

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-09-01 to 2011-09-30	$ 146,493.58	x 100%	$ 146,493.58

Line 108 - Total ITCs and adjustments $ 8,914,793.05

GST/HST Return Summary

Line 101 - Sales and other revenue	$ 96,578,719.18
Line 135 - Total GST/HST new housing rebates (included in line 108)	$ 0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	$ 0.00
Line 105 - Total GST/HST and adjustments for period	$ 16,827,099.73
Line 108 - Total ITCs and adjustments	$ 8,914,793.05
Line 109 - Net Tax	$ 7,912,306.68
Line 110 - Instalments and other annual filer payments	$ 0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	$ 0.00
Line 205 - GST/HST due on acquisition of taxable real property	$ 13,000.00
Line 405 - Other GST/HST to be self-assessed	$ 0.00
Line 114 - Refund claimed	$ 0.00
Amount owing	$ 7,925,306.68

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-10-04

Canada Revenue Agency / Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 935118.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Name	UNION GAS LIMITED
Business Number	119465367RT0001
Reporting period - From date	2011-10-01
Reporting period - To date	2011-10-31
Filing date	2011-11-30

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture) $ 9,370,230.30

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-10-01 to 2011-10-31	$ 114,275.51	x 100%	$ 114,275.51

Line 108 - Total ITCs and adjustments $ 9,255,954.79

GST/HST Return Summary

Line 101 - Sales and other revenue	$ 126,290,520.80
Line 135 - Total GST/HST new housing rebates (included in line 108)	$ 0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	$ 0.00
Line 105 - Total GST/HST and adjustments for period	$ 18,095,798.39
Line 108 - Total ITCs and adjustments	$ 9,255,954.79
Line 109 - Net Tax	$ 8,839,843.60
Line 110 - Instalments and other annual filer payments	$ 0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	$ 0.00
Line 205 - GST/HST due on acquisition of taxable real property	$ 5,200.00
Line 405 - Other GST/HST to be self-assessed	$ 0.00
Line 114 - Refund claimed	$ 0.00
Amount owing	$ 8,845,043.60

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-11-17

Canada Revenue Agency | Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 296698.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Name	UNION GAS LIMITED
Business Number	119465367RT0001
Reporting period - From date	2011-11-01
Reporting period - To date	2011-11-30
Filing date	2011-12-28

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture) $ 9,782,919.82

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-11-01 to 2011-11-30	$ 241,339.74	x 100%	$ 241,339.74

Line 108 - Total ITCs and adjustments $ 9,541,580.08

GST/HST Return Summary

Line 101 - Sales and other revenue	$ 167,131,086.07
Line 135 - Total GST/HST new housing rebates (included in line 108)	$ 0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	$ 0.00
Line 105 - Total GST/HST and adjustments for period	$ 22,940,879.36
Line 108 - Total ITCs and adjustments	$ 9,541,580.08
Line 109 - Net Tax	$ 13,399,299.28
Line 110 - Instalments and other annual filer payments	$ 0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	$ 0.00
Line 205 - GST/HST due on acquisition of taxable real property	$ 0.00
Line 405 - Other GST/HST to be self-assessed	$ 0.00
Line 114 - Refund claimed	$ 0.00
Amount owing	$ 13,399,299.28

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-11-17

Canada Revenue Agency | Agence du revenu du Canada

Canada

Your GST/HST return has been successfully filed.

Your confirmation number is: 225407.

Please print a copy of this confirmation for your records. Do not send us a paper copy of your return.

Thank you for using GST/HST NETFILE.

Business Name	UNION GAS LIMITED
Business Number	119465367RT0001
Reporting period - From date	2011-12-01
Reporting period - To date	2011-12-31
Filing date	2012-01-31

Schedule B

Line 1400 - Gross ITCs and adjustments (before recapture) $ 11,052,641.74

ITC recapture

	Line 1401	Rate	Line 1402
Ontario			
2011-12-01 to 2011-12-31	$ 79,587.63	x 100%	$ 79,587.63

Line 108 - Total ITCs and adjustments $ 10,973,054.11

GST/HST Return Summary

Line 101 - Sales and other revenue	$ 225,413,595.29
Line 135 - Total GST/HST new housing rebates (included in line 108)	$ 0.00
Line 136 - Deduction for pension rebate amount (included in line 108)	$ 0.00
Line 105 - Total GST/HST and adjustments for period	$ 26,347,917.90
Line 108 - Total ITCs and adjustments	$ 10,973,054.11
Line 109 - Net Tax	$ 15,374,863.79
Line 110 - Instalments and other annual filer payments	$ 0.00
Line 111 - Rebates (note: certain forms must be mailed separately)	$ 0.00
Line 205 - GST/HST due on acquisition of taxable real property	$ 130.26
Line 405 - Other GST/HST to be self-assessed	$ 0.00
Line 114 - Refund claimed	$ 0.00
Amount owing	$ 15,374,994.05

If you owe money, you may be able to pay online using CRA's My Payment option, or through your financial institution's Internet banking service. If you choose to pay by cheque or money order please use the RC158, GST/HST Netfile/Telefile Remittance Voucher, that you received with your access code. Please note that your payment may not be reflected on your Notice of Assessment.

Date Modified: 2011-11-17

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 2

a) Please provide the December 31, 2011 audited consolidated financial statements of Union Gas Limited.

b) Please provide the financial statements of each of the corporate entities that are consolidated into the Union Gas Limited December 31, 2011 Consolidated Financial Statements requested above. Please provide the 2011 unconsolidated financial statements either audited or unaudited of the company that owns the distribution business that underpins the Ontario regulated utility disclosures for which the earnings sharing calculation applies.

c) Given Union's 2011 Audited Financial Statements were issued on March 21, 2012 and published on SEDAR (on March 23, 2012), please reconcile the 2011 actual revenues, expenses and income figures in the EB-2012-0087 schedules to the 2011 Audited Financial Statements.

d) Please provide a reconciliation of the Statement of Utility Income for the year ended December 31, 2011 that is used in the Earnings Sharing calculations to the 2011 audited consolidated income statement. Please explain any significant differences.

e) Please provide all the background information and calculations used to determine the benchmark ROE.

Response:

a) Please see Attachment 1.

b) Filed under separate confidential cover.

c) Please see Attachment 2.

d) Please see the response at c) above.

e) The benchmark return on equity of 8.10% is based on the October 2010 Formula Based ROE as calculated in the table below.

	Oct-10
10 Year Consensus Forecast	
3 Month	2.80%
12 Month	3.30%
Average	3.05%
Average Spread on 10 & 30 Year Canadian Bonds	0.60%
Long Canada	3.65%
Risk Premium	**3.55%**
Adjustment factor	0.90%
Formula Based ROE	**8.10%**


uniongas
A Spectra Energy Company
CELEBRATING
100 YEARS
Est. 1911

Stephen W. Baker
President

March 21, 2012

Dear Shareholder:

I am pleased to forward you a copy of the Union Gas Limited (Union Gas) 2011 annual report. It contains Union Gas' management's discussion and analysis, management responsibility for financial reporting, consolidated financial results, and corporate directory. I invite you to visit www.sedar.com for electronic versions of Union Gas' consolidated financial statements, management's discussion and analysis, and other filings throughout the year.

Stephen W. Baker
President

This discussion and analysis of Union Gas Limited for the twelve months ended December 31, 2011, should be read in conjunction with the audited consolidated financial statements and accompanying notes. The terms ("we," "our", "us" and "Union Gas") as used in this report refer collectively to Union Gas Limited and its subsidiary unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. The results reported herein have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in millions of Canadian dollars except where noted. Additional information relating to us, including our most recent Annual Information Form, can be found at www.sedar.com.

FORWARD LOOKING INFORMATION

This Management's Discussion and Analysis (MD&A) includes forward-looking statements. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- local, provincial and federal legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of storms;
- the timing and extent of changes in commodity prices and interest rates;
- general economic conditions which can affect the long-term demand for natural gas and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- the development of alternative energy resources;
- results of financing efforts, including the ability to obtain financing on favourable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop pipeline, storage, and other infrastructure projects and the effects of competition;
- the performance of transmission, storage and distribution facilities;
- the extent of success in connecting natural gas supplies to transmission systems and in connecting to expanding gas markets;
- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets during the periods covered by the forward-looking statements; and

- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

GENERAL

Union Gas, one of Canada's Top 100 Employers for 2011, is a major Canadian natural gas storage, transmission and distribution company based in Ontario with 100 years of experience and service to customers. The distribution business serves approximately 1.4 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' growing storage and transmission business offers premium storage and transportation services to customers at the Dawn Hub (Dawn). Dawn is the largest underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and United States (U.S.) supply basins to markets in central Canada and the northeast U.S.

Our distribution system consists of approximately 62,700 kilometres of main and service pipelines. Distribution pipelines carry or control the supply of natural gas from the point of local supply to customers. Our underground natural gas storage facilities have a working capacity of approximately 155 billion cubic feet (Bcf) in 23 underground facilities located in depleted gas fields. The transmission system consists of approximately 4,700 kilometres of high-pressure pipeline and six mainline compressor stations.

Union Gas' common shares are held by Great Lakes Basin Energy L.P., a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Spectra Energy is a Delaware corporation that is a public company in the U.S. and whose shares are listed on the New York Stock Exchange.

Our board of directors is comprised of at least one-third independent directors with the remainder consisting of officers of Union Gas, Westcoast or Spectra Energy and there is no audit committee of the board. The function of an audit committee is carried out at the level of Spectra Energy during the review of its consolidated financial statements.

HIGHLIGHTS

($millions except where noted)	For the Years Ended December 31 **2011**	2010	2009
Income			
Total operating revenues	**1,813**	1,830	2,019
Earnings applicable to common shares	**199**	204	173
Dividends			
Dividends on preference shares	**2**	2	2
Dividends on common shares	**145**	190	165
Assets and long-term liabilities			
Total assets	**5,845**	5,585	5,446
Total long-term liabilities	**3,291**	2,935	2,870
Volumes of gas (10^6m^3)[1]			
Distribution volumes	**14,133**	13,314	12,849
Transportation volumes	**23,619**	25,577	22,668
Total throughput	**37,752**	38,891	35,517
Customers *(thousands)*	**1,360**	1,344	1,325
Heating degree days[2] *(degree Celsius)*			
Actual	**3,957**	3,796	4,130
Normal[3]	**4,075**	4,056	4,034

[1] 10^6m^3 equals millions of cubic meters. One cubic meter is equivalent to 35.31467 cubic feet.
[2] A heating degree day is a measure of temperature that identifies the need for heating. A degree day occurs when the average temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius equals 18 heating degree days.
[3] As per OEB approved methodology used in setting rates.

RESULTS OF OPERATIONS

	For The Three Months Ended December 31			For The Years Ended December 31		
($millions)	2011	2010	**Increase (Decrease)**	2011	2010	**Increase (Decrease)**
Gas sales and distribution revenue	404	441	**(37)**	1,468	1,493	**(25)**
Cost of gas	209	238	**(29)**	755	794	**(39)**
Gas distribution margin	195	203	**(8)**	713	699	**14**
Storage and transportation revenue	78	78	**-**	311	308	**3**
Other revenue	13	6	**7**	34	29	**5**
	286	287	**(1)**	1,058	1,036	**22**
Expenses	165	160	**5**	645	631	**14**
Interest expense	40	41	**(1)**	152	158	**(6)**
Income taxes	17	8	**9**	60	41	**19**
Net income and comprehensive income	64	78	**(14)**	201	206	**(5)**
Preference share dividends	-	-	**-**	2	2	**-**
Net income applicable to common shares	64	78	**(14)**	199	204	**(5)**

Three month period ended December 31, 2011 compared to three month period ended December 31, 2010

Gas sales and distribution revenue. The $37 million decrease was mainly driven by:

- a $17 million decrease in customer usage of natural gas primarily due to weather that was 17% warmer than in the same period in 2010,
- a $12 million decrease from lower natural gas prices[4] passed through to customers without a mark-up, and
- a $9 million decrease due to higher earnings to be shared with customers.

Cost of gas. The $29 million decrease was mainly driven by:

- a $12 million decrease from lower natural gas prices passed through to customers,
- an $11 million decrease in fuel and operating costs, and
- a $7 million decrease due to lower volumes of natural gas sold primarily due to weather that was 17% warmer than in the same period in 2010.

Other revenue. The $7 million increase was primarily due to incentives from customer energy conservation programs.

Expenses. The $5 million increase was primarily due to higher employee benefit costs.

Income taxes. The $9 million increase was due to a higher effective tax rate partially offset by lower pre-tax income.

[4] Natural Gas prices passed through to customers without a mark-up are adjusted quarterly based on the 12 month New York Mercantile Exchange

Twelve month period ended December 31, 2011 compared to twelve month period ended December 31, 2010

Gas sales and distribution revenue. The $25 million decrease was mainly driven by:

- a $141 million decrease from lower natural gas prices passed through to customers without a mark-up, and
- a $12 million decrease due to higher earnings to be shared with customers, partially offset by
- a $118 million increase in customer usage of natural gas primarily due to weather that was more than 4% colder than in the same period in 2010, and
- a $15 million increase from growth in the number of customers.

Cost of gas. The $39 million decrease was mainly driven by:

- a $141 million decrease from lower natural gas prices passed through to customers, and
- a $5 million decrease in fuel and operating costs, partially offset by
- a $106 million increase due to higher volumes of natural gas sold primarily due to weather that was more than 4% colder than in the same period in 2010, and
- a $10 million increase from growth in the number of customers.

Storage and transportation revenue. The $3 million increase was mainly driven by:

- a $10 million increase in short-term transportation due to higher exchange service revenue, partially offset by
- a $7 million decrease primarily due to lower storage prices.

Other revenue. The $5 million increase was primarily due to incentives from customer energy conservation programs.

Expenses. The $14 million increase was primarily the result of higher employee benefit costs.

Income taxes. The $19 million increase was due to a higher effective tax rate and higher pre-tax income.

QUARTERLY RESULTS

($millions)	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Q1 2011	Q2 2011	Q3 2011	Q4 2011
Gas sales and distribution revenue	608	258	186	441	599	276	189	404
Storage and transportation revenue	81	74	75	78	83	78	72	78
Other revenue	6	8	9	6	5	7	9	13
Total operating revenues	695	340	270	525	687	361	270	495
Net income and comprehensive income	85	28	15	78	97	35	5	64
Net income applicable to common shares	84	28	14	78	96	35	4	64

Seasonal Trends

The natural gas distribution business is highly seasonal due to volume-based rates and the significant effect of the winter heating season on volumes. This is typically reflected in strong first quarter results, second and third quarters that show either small profits or losses and strong fourth quarter results, subject to the impact of weather variations relative to demand during the winter heating season. Changes in natural gas rates that are charged to customers result in corresponding changes in gas sales and distribution revenue. These increases or

decreases in gas sales revenue are completely offset in the cost of gas, as a result of the associated regulatory recovery and refund mechanisms.

RATE REGULATION

Union Gas is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the Ontario Energy Board Act (1998), which is part of a package of legislation known as *The Energy Competition Act* (1998). This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario. We are subject to regulation with respect to the rates that we may charge our customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting practices.

Since 2006, Union Gas has provided storage services to customers outside its franchise area and new storage services under a framework established by the OEB that supports unregulated storage investments and allows Union Gas to compete against third-party storage providers on the basis of price, terms of service and flexibility and reliability of service. Under that framework, Union Gas was required to share its long-term storage margins with ratepayers until 2011, following which no sharing of margins is required. Existing storage services to customers within Union Gas' franchise area continue to be provided at cost-based rates.

Incentive Regulation

Our distribution rates, beginning January 1, 2008 are set under a multi-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The incentive regulation framework allows for annual inflationary rate increases, offset by a productivity factor of 1.82% that is fixed for each year. The framework also allows for rate increases in the small volume customer classes where average use is declining, a five-year term, certain adjustments to base rates, the continued pass-through of gas commodity, upstream transportation and demand side management costs, an allowance for unexpected cost changes that are outside of management's control, and earnings sharing between Union Gas and our customers beyond specified earnings levels and equal sharing of tax changes between Union Gas and customers.

In late 2011, the OEB approved Union Gas' 2012 regulated distribution, storage and transmission rates as determined pursuant to the incentive regulation framework. Changes to Union Gas' revenues are not expected to be material as a result of the new rates.

Since 2012 is the final year of our current multi-year incentive regulation framework, we filed an application with the OEB in November 2011 to set our distribution rates under traditional cost-of-service regulation effective January 1, 2013. We plan to file our application for a new multi-year incentive regulation framework after receiving the OEB's decision on our 2013 rates application. The OEB's decision on our 2013 rates application is expected in late 2012.

Non-Commodity Deferral Account Disposition

In April 2011, we applied for the annual disposition of the 2010 non-commodity deferral account balances and the impact of incentive regulation earnings sharing for 2010. The OEB approved a refund payable to customers of approximately $10 million in January 2012 with implementation of the refund proposed to commence April 1, 2012 for a six-month period.

Commodity Rates

Union Gas and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis (Quarterly Rate Adjustment Mechanism), to ensure that customers' rates reflect future expected prices to the extent reasonably possible. The difference between the approved and the actual cost of gas incurred is deferred for future recovery from or repayment to customers. These differences are included in quarterly gas commodity rates and recovered from or refunded to customers over the subsequent twelve months and are also subject to

review and approval by the OEB on an annual basis. This allows us to adjust customer rates closer to the time of incurrence.

Cost of Capital

In December 2009, the OEB issued its policy report on the Cost of Capital for Ontario's Regulated Utilities. In that report, the OEB determined that Union Gas' utility return on equity should be increased by approximately 125 basis points. The OEB also determined that it would only apply the conclusions from its policy report during cost-of-service applications. As we are currently under a five-year incentive regulation framework, we have incorporated the OEB's policy report determinations in our cost-of-service application for 2013 rates.

Sale of the St. Clair Line

In November 2009, the OEB approved the sale of the St. Clair Line to the Dawn Gateway Pipeline Limited Partnership (DGP), an affiliate company, with such approval expiring on December 31, 2013. The St. Clair Line runs approximately 12 kilometres in the Township of St. Clair located in southwestern Ontario, and was constructed in 1988 to bring new and additional gas supplies to Dawn. The need for the St. Clair Line was largely replaced by the construction of the Vector Pipeline interconnect into the Sarnia Industrial Line in 2005, such that the St. Clair Line was underutilized.

The OEB determined that the sale price of the St. Clair Line for ratemaking purposes should be set at a value higher than net book value and that ratepayers should receive a credit for the cumulative under-recovery in rates of the St. Clair Line from 2003 to the date of sale. Accordingly a credit of $6.4 million was recorded in a deferral account. The OEB also directed Union Gas to record the effect of removing the assets, revenues and costs of the St. Clair Line from regulated operations in a deferral account.

Due to changing market conditions, the construction of the Dawn Gateway pipeline was delayed, and in May 2011, the OEB released its decision finding that the deferral accounts will only be disposed of to ratepayers if the sale of the St. Clair Line is completed, on or before December 31, 2011.

In December 2011, DGP determined that there is insufficient shipper support for the Dawn Gateway Pipeline project at this time. Accordingly the sale of the St. Clair Line has been cancelled and the total deferral account balance of $8.5 million has been taken into income. The St. Clair Line will be returned to regulated rate base upon OEB approval.

Jacob Pool

In June 2010, Union Gas purchased a depleted gas reservoir in the Municipality of Chatham-Kent from Torque Energy Inc. and Liberty Oil & Gas Ltd., known as Jacob Pool. In July 2011, the OEB approved Jacob Pool to be designated as a gas storage area and authorized the injection, storage and removal of gas from this area. Further development of Jacob Pool has been suspended and will be restarted when the market conditions improve.

Demand Side Management

The OEB has been consulting with stakeholders on the guidelines for the next multi-year Demand Side Management (DSM) framework for the natural gas utilities. Final guidelines were issued by the OEB on June 30, 2011. These guidelines allow for annual inflationary increases to the DSM budget, and introduce some changes to the program portfolio. In September 2011, Union Gas filed its DSM plan for 2012-2014 for approval by the OEB. Settlement conferences were held in December 2011 and January 2012. These discussions resulted in a comprehensive three-year settlement on most issues. In February 2012, the OEB accepted the settlement agreement and issued its decision on the unsettled issues. No material impact on Union Gas is expected to result from that decision.

Generally Accepted Accounting Principles of the United States of America (U.S. GAAP)

Union Gas' 2013 rates application uses U.S. GAAP as the basis for the revenue and cost forecasts contained in that application. Since the OEB only approved the use of Canadian GAAP as the appropriate basis for setting rates and for regulatory reporting, the OEB set out a process to hear submissions on the use of U.S. GAAP as a preliminary matter in Union's 2013 rates application. In March 2012, the OEB approved the use of U.S. GAAP for regulatory purposes.

LIQUIDITY AND CAPITAL RESOURCES

We manage cash to maximize value while assuring appropriate amounts of cash are available, as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for the safety of principal and for liquidity, and accordingly do not include equity-based securities.

We meet our short-term cash requirements through funds generated from operations, the utilization of loans from Westcoast, and the issuance of commercial paper. Long-term capital requirements for expansion, maintenance and investments are met through the combination of cash flow from operations, issuance of long-term debt and preference shares.

Changes in Cash Flow

	For The Years Ended December 31	
($millions)	**2011**	2010
Operating activities	**354**	174
Investing activities	**(290)**	(232)
Financing activities	**(74)**	36

Operating Activities

Union Gas' heating season extends from approximately November through March. We begin the heating season with near-capacity natural gas inventory levels which are drawn throughout the heating season. Inventory levels decrease from December and thus contribute to a positive cash flow from operations during the first quarter. After the heating season ends, inventory is replenished for the next heating season. During the third quarter, gas inventory injections typically exceed withdrawals, negatively affecting cash flows. During the fourth quarter inventory decreases as withdrawals exceed injections.

Some of our customers purchase gas directly from marketers. Marketers typically deliver gas to us evenly throughout the year, whereas most of their customers use gas based on seasonality. As part of our normal billing process, we bill the marketers' customers as gas is used and remit this cash to the marketer when gas is delivered to us. Therefore, during the first and fourth quarters of the year, customers typically use more gas than is delivered to us and we collect cash from the marketers' customers creating a positive cash flow. During the second and third quarters, marketers deliver more gas than their customers use, thus creating a significant cash outflow. These are normal seasonal trends.

The primary factors impacting cash flow from operations for 2011 compared to 2010 include higher refunds to customers in 2010 of gas costs collected in 2009 and a large final tax payment in the first quarter of 2010 for 2009 taxes, partially offset by higher gas purchases in 2011.

Investing Activities

The table below is a summary of capital expenditures:

	For The Years Ended December 31		
	2012	2011	2010
	(estimated)		
Storage and transmission projects	33%	34%	25%
Distribution	53%	51%	59%
General equipment	14%	15%	16%
	100%	100%	100%
Total capital expenditure ($millions)	$301	$290	$232

The table below is a summary of capital project type:

	For The Years Ended December 31		
	2012	2011	2010
	(estimated)		
Maintenance projects[5]	84%	98%	97%
Expansion projects	16%	2%	3%
	100%	100%	100%

Capital expenditures for 2011 were higher compared to 2010 primarily due to spend on two multi-year maintenance projects that were started in 2010 and substantially completed in 2011. Expansion expenditures in 2012 are expected to be higher than 2011 partially offset by lower 2012 maintenance expenditures, due to the substantial completion of the two multi-year projects. The 2012 expansion expenditures reflect our continued assessment of the timing of projected long-term market requirements and general economic conditions. Based on our current assessment, we believe that expansion opportunities will continue to exist in the future.

As outlined in the financing activities discussion that follows, we have sufficient financing available to meet our investing requirements. Management expects that financing of 2012 projects will be done through a combination of cash generated from operations and available debt facilities.

Financing Activities

We have the following financing arrangements in place:

- A shelf prospectus was filed in September 2010 that permits the issuance of medium-term notes, in one or more series, up to an aggregate principal amount of $500 million and for terms as covered in the pricing supplement at the time of issue with maturities of not less than one year from the date of issue. The shelf will expire in October 2012. As of December 31, 2011, $200 million was available.
    - In May 2011, we retired, at par, $250 million of Series 3 medium-term note debentures at 6.65% per annum.
    - In June 2011, we issued $300 million of Series 9 medium-term note debentures at 4.88% per annum, due June 2041. Net proceeds from the offering have been used for general corporate purposes, including refinancing of the May 2011 retirement.
- In December 2011, the previous $500 million committed credit facility was replaced by a $400 million committed credit facility. This committed credit facility is available to help meet our short-term financing needs. As of December 31, 2011, $121 million was available.

[5] Maintenance projects include costs incurred for new customer attachments. Maintenance projects also include expansion capital for in-franchise customers.

- Our $400 million committed credit facility has a five year term which expires in December 2016 and includes a provision which requires us to repay all borrowings under the facility for a period of two days during the second quarter of each year. This facility is intended to be used primarily to manage the significant changes in working capital experienced by Union Gas as a result of volumes and prices associated with natural gas purchases and sales. Most of the short-term cash requirements are funded through issuing commercial paper at rates generally below the lender's prime rate. Our 2011 commercial paper peaked in December at approximately $279 million.

In order to maintain the common equity component of the capital structure at a level no greater than that approved by the OEB, we typically pay a quarterly dividend to our parent company. During 2011, we paid a quarterly dividend to our parent of $16 million (2010 –$16 million). In December 2011, we paid an additional $80 million dividend to our parent (December 2010 – $125 million).

OUTSTANDING SHARES

	December 31 2011	December 31 2010
Redeemable Preference Shares		
Class A, Series A, 5.5%	**47,672**	47,672
Class A, Series C, 5.0%	**49,500**	49,500
Preference Shares		
Class A, Series B, 6.0%	**90,000**	90,000
Class B, Series 10, 4.88%	**4,000,000**	4,000,000
Common Shares	**57,822,650**	57,822,650

FINANCIAL CONDITION

Ratings Summary

	Standard & Poor's	**DBRS**
Commercial paper	A – 1 (low)[6]	R – 1 (low)
Debentures	BBB+	A
Preference shares	P – 2 (low)[7]	Pfd – 2

Our credit ratings remain unchanged from those reported in the 2010 Annual Report.

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, our results of operations, market conditions and other factors. Our credit ratings could impact our ability to raise capital in the future, impact the cost of our capital and, as a result, have an impact on our liquidity.

[6] Represents Canadian National Scale Commercial Paper Rating.
[7] Represents Canadian Preferred Stock Rating.

CONTRACTUAL OBLIGATIONS

The table below is a summary of our contractual payment obligations, due by period.

($millions)	**Total**	**2012**	**2013-2014**	**2015-2016**	**Thereafter**
Long-term debt[8]	4,397	150	441	599	3,207
Redeemable preference shares	5	–	–	–	5
Operating leases	32	6	13	13	–
Purchase obligations[9]	953	526	215	134	78
Environmental obligations[10]	16	4	4	4	4
Contributions to employee future benefit plan[11]	64	64	–	–	–
Total contractual obligations[12]	5,467	750	673	750	3,294

RELATED PARTY TRANSACTIONS

We purchase gas, storage and transportation services at prevailing market prices and under normal trade terms from related parties. During the year ended December 31, 2011, these purchases totalled $56 million (2010 – $11 million). Union Gas also provides storage and transportation services to related parties which totalled $1 million during 2011 (2010 – $1 million).

We provided administrative, management and other services to related parties totalling $12 million (2010 – $10 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $9 million (2010 – $9 million).

At December 31, 2011 we have receivable balances of $4 million (2010 – $2 million) and payable balances of $7 million (2010 – $3 million) with related parties, all of which are recorded in accounts receivable and accounts payable, respectively.

During 2011, we obtained from and provided unsecured loans to Westcoast. The balance outstanding on these loans at December 31, 2011 was a $99 million payable (2010 – $198 million payable). Interest received on these loans during 2011 totalled less than $1 million (2010 – less than $1 million) and interest paid on these loans totalled less than $1 million (2010 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

[8] Includes: estimated scheduled interest payments over the life of the associated debt.

[9] Includes: firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; contractual obligations for engineering, procurement and construction costs for pipeline projects.

[10] Includes capital, operating and maintenance expenditures related to the comprehensive certificate of approval.

[11] We are unable to reasonably estimate employee future benefit plan contributions beyond 2012 due primarily to uncertainties about market performance of plan assets.

[12] Excludes cash obligations for asset retirement activities. The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Union Gas may use internal resources or external resources to perform retirement activities. Amounts also exclude reserves for litigation, environmental remediation, annual insurance premiums that are necessary to operate the business and regulatory liabilities because Union Gas is uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts exclude future income taxes and investment tax credits on the Consolidated Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year.

GAS SUPPLY

The gas supply portfolio of Union Gas primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. These contracts are indexed to either the New York Mercantile Exchange natural gas futures contracts, the Canadian Gas Price Reporter that publishes Alberta index prices or the Platt's Inside FERC Dawn Monthly Index.

We continue to monitor and evaluate the new and changing natural gas supply dynamics to determine what opportunities exist for our customers. We have taken steps to allow for the emerging Marcellus Shale gas supplies to serve our Ontario system customers beginning in 2012, including contracting for firm transportation capacity on other pipelines to facilitate moving this supply to Dawn and ultimately to our customers.

OUTLOOK

Gas Sales and Distribution

Demand for natural gas in all markets is expected to remain flat through 2012. Any growth driven by continued low natural gas prices is expected to be offset by reductions in distribution throughput. Distribution throughput is forecasted to continue declining as a result of energy conservation including our DSM initiatives, declining normalized use per customer and a general trend toward warmer weather.

Union Gas continues to focus on promoting conservation and energy efficiency through our DSM programs. In 2010 and 2011, we spent $22 million and $26 million respectively, promoting these programs. We plan to spend approximately $31 million in 2012.

Storage and Transportation

The storage and transportation marketplace continues to deal with the global economic slowdown but is expected to be stable going forward. Weak commodity prices as a result of a more robust North American gas supply balance and narrower seasonal price spreads in the marketplace are resulting in lower unregulated storage values. North American natural gas supplies continue to increase as a result of new supply attachment including liquefied natural gas and development in the U.S. Rocky Mountains, as well as various new shale gas resource projects such as the Barnett, Fayetteville, Woodford and the Marcellus and Utica Shale areas. The development of these new resources has increased overall North American gas supply reserves and is leading to significant new pipeline and storage infrastructure to connect these new supplies to the North American pipeline grid and the associated natural gas consuming market areas. These new supply sources will be available to serve Ontario and Eastern Canadian markets.

Furthermore, we are experiencing a change in traditional natural gas flow patterns as these new shale gas supplies continue to develop. This will continue to provide Union Gas opportunities and challenges for new storage and pipeline infrastructure projects. Union Gas applied to the OEB, during 2010 and again in 2011, for transportation service enhancements to respond to these changing flow patterns. These services were approved by the OEB and will enhance access to emerging supply basins and provide enhanced flexibility to attract gas to Dawn, where it can be stored and delivered to downstream eastern markets.

The location of our storage and transportation facilities, with interconnections between major U.S. markets in the Great Lakes region and the U.S. Northeast continues to support long-term growth opportunities for us. It is our expectation that demand for natural gas in North America will continue to have low growth over the long-term with continued growth in peak day demands.

In September 2011, TransCanada PipeLines Limited (TCPL) filed a proposal with the National Energy Board (NEB) to modify their tolling framework. With the potential for additional long-haul and/or short-haul toll changes, customers may continue to pursue alternative or less expensive sources of delivered supply. Since our system directly connects to the TCPL system, this could result in a decline in the use of our storage and transportation system. Also, declining supply into Dawn from the TCPL system and constraints in takeaway capacity downstream of Union's Parkway compressor station site on the TCPL system may affect liquidity at

Dawn and storage pricing. To address these concerns, we will continue to focus on adding new services to attract new supply to Dawn. We are also evaluating new infrastructure projects that can more directly connect downstream markets and upstream supply to Dawn.

Environmental, Health and Safety

During 2008, we obtained approval from the Ontario Ministry of the Environment (MOE) for a multi-site comprehensive certificate of approval (CC of A) for the permitting of our air and noise emission sources. The CC of A will treat Union Gas as a single integrated natural gas storage, transmission and distribution system incorporating all storage pools, metering and regulating stations, compressor stations and buildings into a single environmental permit. The terms and conditions of the CC of A include significant financial obligations for capital, operating and maintenance expenditures over a period of approximately 10 years, and the total estimated obligation has been included in the Contractual Obligations section of this document. Under the terms of the CC of A, we will be allowed to add and modify facilities without prior approval from the MOE, thereby reducing the risk of delays associated with obtaining environmental permits. Union Gas remains on target to meet the current 10 year plan.

The MOE requires third party audits to confirm that our facilities are operating in accordance with the conditions specified in the CC of A. There have been no major findings to date from these audits.

In May 2011, the Workplace Safety and Insurance Board conducted a Workwell audit at our Company. This audit occurred as a result of an employee vehicle fatality in late 2009. At the conclusion of the audit, we were notified that we had successfully passed the audit and that we were one of a very few multi-site companies in Ontario to have ever passed an audit on the first attempt. This result is a recognition that we not only meet compliance standards, but also have a very strong safety culture.

Global Climate Change

Policymakers at provincial, federal and international levels continue to evaluate potential legislative and regulatory compliance mechanisms to achieve reductions in global greenhouse gas (GHG) emissions in an effort to address the challenge of climate change. It is likely that our assets and operations are or will become subject to direct and indirect effects of current and possible future global climate change regulatory actions in the jurisdictions in which those assets and operations are located. See Risk Factors – Global Climate Change Risk for further discussion.

RISK FACTORS

Our earnings are affected by the risks inherent in the natural gas industry and energy marketplace. In general, our business and earnings level may be adversely affected by a number of risks as described below.

Market Risk

Sales to industrial customers are affected by general economic conditions, the absolute and relative price of alternative energy sources, foreign exchange rates and global competition. In 2012, we expect that the North American economy will experience slow growth.

Sales to Union Gas' residential, small commercial and small industrial customers are affected by the number of new customer additions to the system, the price of natural gas, the warming trend in weather that is not fully reflected in rates, and the continued shift to higher efficiency. New customer additions in 2012 are expected to remain flat relative to 2011, however, the ongoing trend towards energy efficiency will continue to put pressure on usage.

A large quantity of our transportation capacity is subject to renewal on an annual basis. Our standard contract terms provide automatic renewal of contracts, after the initial term, for one year at a time unless the customer provides two years prior notice of termination. Due to changing gas supply patterns we have received notice of termination for some capacity in 2012 and 2013 and have continued risk of further contract termination beyond 2013.

For storage contracts, our standard contract terms do not allow for renewals but will typically have contract terms of one to five years.

Commodity Price Risk

Fluctuations in natural gas prices affect our gas purchase costs for our own operating requirements as well as for the gas supply costs we incur for and collect from our system customers. Our gas procurement policy primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. Commodity price volatility and absolute price levels also impact the amount of natural gas used by customers.

Credit Risk

Credit risk represents the loss that we could incur if a counterparty fails to perform under its contractual obligations. We analyze the customer's financial condition prior to entering into an agreement, obtain collateral when appropriate, establish credit limits and monitor the appropriateness of those limits on an ongoing basis.

Our credit exposure consists of both the risk of collecting receivables for services provided as well as the risk related to gas imbalances that occur as a regular part of the services provided in both the direct purchase market and ex-franchise market.

In the normal course of operations, we provide gas loans to other parties from our holdings of gas in storage. The replacement cost of the gas on loan at December 31, 2011 was $64 million (2010 – $72 million). We manage our credit exposure related to gas loans by subjecting these parties to the same credit policies used for all customers.

Weather Risk

As a primary component of Union Gas rates is volume based, the revenue levels approved by the OEB are impacted by weather. The volume forecasts used to determine the rates approved by the OEB assume normal weather conditions. Normal weather, as mandated by the OEB, is based on a 55:45 weighting of the 30-year average forecast and 20-year trend forecast respectively, for 2008 forward. Since a large portion of the gas distributed to the residential and commercial markets is used for space heating and is charged using volume-based rates, differences from normal weather have a significant effect on the consumption of gas and on our financial results.

Regulatory Risk

Our natural gas assets and operations are subject to regulation by federal, provincial and local authorities including the OEB and by various federal and provincial authorities under environmental laws. Regulation affects almost every aspect of our business, including the ability to determine terms and rates for services, acquisitions, construction, expansion and operation of facilities, issuance of equity or debt securities, and dividend payments.

In addition, regulators in Canada have taken actions to strengthen market forces in the gas pipeline industry, which have led to increased competition. In a number of key markets, natural gas pipeline and storage operators are facing competitive pressure from a number of new industry participants, such as alternative suppliers as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on our business, earnings, financial condition and cash flows.

Most of our pipelines are regulated by the Ontario Technical Standards and Safety Authority (TSSA) while a few are regulated by the NEB. Through our participation on the TSSA Natural Gas Advisory Council and associated Risk Reduction Groups we have the opportunity to provide input and to influence the direction of regulatory changes. Union Gas currently has a robust integrity management program, however amendments to the Ontario regulations being proposed by the TSSA will have an impact on our Integrity Management Program and the direction the U.S. industry is taking may prompt some further regulatory requirements. Specifically the changes being proposed include adopting the 2011 version of CSA Z662, adopting a newly developed security management standard, including the requirements for a utility cross bore program which was already included

in a separate Director's Order, and introducing the requirements to identify high consequence areas and consider additional measures to mitigate potential pipeline risk in those areas. We continue to work with the TSSA in their development of the amendments to the Ontario regulations. We have very limited NEB regulated assets, so the amendments proposed related to NEB Management Systems and Performance Measures are not expected to have a significant impact on our business.

Competition Risk

As our distribution business is regulated by the OEB, it is generally not subject to third-party competition within our distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of newly-required facilities even within our distribution franchise area may be permitted. In addition, other companies could enter our markets or regulations could change.

Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Storage Market Risk

We use market based prices for some of our storage operations and sell our storage services based on natural gas market spreads and volatility. If natural gas market spreads or volatility deviate from historical norms or there is significant growth in the amount of storage capacity available to natural gas markets relative to demand, our approach to managing our market-based storage capacity portfolio may not protect us from significant variations in storage revenues, including possible declines as contracts renew.

Permit Fees Risk

Effective January 1, 2007, the Government of Ontario granted municipalities the right to charge a fee to recover the costs of issuing a permit to access pipelines located within a municipal roadway. During 2011, permit fees levied by municipalities against Union Gas did not have a significant impact on our consolidated financial statements. Should more municipalities start implementing a permit fee or if the amounts increase and these assessments become significant in the future, Union Gas will apply to the OEB to recover the annual cost of these fees in rates.

Financing Risk

Our business is financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from operations and to fund investments originally financed through debt. Our long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us below investment-grade, our borrowing costs would increase, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

We are subject to long-term debt covenants that include a limitation on the payment of dividends, and requirements for specific interest coverage ratios prior to the issuance of additional long-term debt. Although we do not anticipate any impact to our current financing plans, reduced earnings may limit the payment of future dividends and the level of new long-term debt available to us. We maintain a revolving credit facility to backstop our commercial paper programs for short-term borrowings. This facility includes a financial covenant which limits the amount of debt that can be outstanding as a percentage of total capital. Failure to maintain this covenant could preclude us from issuing commercial paper or borrowing under the revolving credit facility and could require immediate pay down of any outstanding drawn amounts under other revolving credit agreements, which could adversely affect our cash flow.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be adversely affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings could make our costs of borrowing higher or access to funding sources more limited.

Human Resources Risk

Union Gas' workforce consists of both unionized and non-unionized employees. Labour disruptions associated with the collective bargaining process can affect our ongoing operations. Projected changes in workforce demographics and a future shortage of skilled trades represent an issue that is being addressed by Union Gas.

Performance Risk

We have extensive contractual relationships with natural gas producers, customers, marketers, commercial enterprises, industrial companies, and others. The risk of non-performance by a contracting party may be analyzed and reduced but it cannot be entirely eliminated. Ongoing consolidation of customers and partners may increase the severity of a default.

Litigation Risk

Union Gas, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Although it is possible that liabilities may be incurred in instances for which no accruals have been made, we have no reason to believe that the ultimate outcome of such matters currently known to us could have a material effect on our consolidated financial statements.

Facility Risk

We carry on business through a large and complex array of natural gas transmission, storage and distribution assets. These facilities, like any other industrial operations, are subject to outages from time to time. Depending on circumstances, such outages may result in loss of revenues and/or increased maintenance costs.

Political Risk

In 2011, the Ontario Liberal Government was re-elected, albeit with a minority number of seats in the legislature. The province is operating with a large financial deficit and significant spending commitments. As such, it is expected that they will continue to search for new sources of revenues including non-tax revenue streams such as fees and levies.

Environmental, Health and Safety Risk

There are a variety of hazards and operating risks inherent in natural gas storage, transmission, and distribution activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we might maintain may not fully cover the damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on our business, earnings, financial condition and cash flows.

Global Climate Change Risk

The current international climate framework, the United Nations-sponsored Kyoto Protocol, prescribes specific targets to reduce GHG emissions for developed countries for the 2008-2012 periods. United Nations-

sponsored international negotiations were held in Copenhagen, Denmark in December 2009, in Cancun, Mexico in December 2010 and in Durban, South Africa in December 2011 with the intent of defining a future agreement for 2012 and beyond. In December 2011 after the international negotiations in Durban, South Africa, Canada announced that it is withdrawing from the Kyoto Protocol.

In 2008 the government outlined a regulatory framework mandating GHG reductions from large final emitters. Regulatory design details from the Government of Canada remain forthcoming. However, Canada has reaffirmed its strong preference for a harmonized approach with that of the U.S. Regardless of the timing, we expect a number of our assets and operations will be affected by pending federal climate change regulations. However, the materiality of any potential compliance costs is unknown at this time as the final form of the regulation and compliance options has yet to be determined by policymakers.

A number of provinces are establishing or considering provincial or regional programs that would mandate reductions in GHG emissions including Ontario which is a member of the Western Climate Initiative which also includes the provinces of British Columbia, Manitoba and Quebec. However, the key details of future GHG restrictions and compliance mechanisms remain largely undefined.

In 2011, Ontario regulations for GHG emissions reporting came into effect. The regulation applies to all facilities emitting greater than 25,000 tonnes of carbon dioxide per year from a list of specified activities. Currently, Union Gas is required to report and verify emissions based on general stationary combustion (compressor engines, generators, heaters and boilers).

Due to the uncertainty of Canadian federal and provincial policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However such legislation could increase our operating costs materially, require material capital expenditures or create additional permitting, which could delay proposed construction projects.

Protecting Against Potential Terrorist Activities

The potential for terrorism because of the high profile of the natural gas industry has subjected our operations to increased risks that could have a material adverse effect on our business. This risk is particularly great for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our cash flows and business.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Pension Risk

Our costs of providing defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates used to measure pension liabilities, actuarial gains and losses, future government regulation and our contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of our plan assets, and depending upon the other factors impacting our costs as listed above, we could experience net asset, expense and funding volatility. This volatility could have a material effect on our earnings and cash flows.

Land Rights

Certain aboriginal groups in Ontario have claimed aboriginal and treaty rights in areas where Union Gas' Dawn storage and transmission assets are located and also in areas where the Dawn-Trafalgar pipeline route is located. The existence of these claims could give rise to future uncertainty regarding land tenure depending upon their negotiated outcome.

CERTIFICATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

We have established and maintained disclosure controls and procedures designed to: (a) provide reasonable assurance that material information required to be disclosed by us is accumulated and communicated to management to allow timely decisions regarding required disclosure; and (b) ensure that material information required to be disclosed by us is recorded, processed, summarized, and reported within the time periods specified in applicable securities legislation.

Our management, with the participation of the President and the Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2011, and, based upon this evaluation, the President and the Chief Financial Officer have concluded that these disclosure controls and procedures, as defined by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings (NI 52-109), are effective for the purposes set out above.

Internal Control over Financial Reporting

Our management is responsible for designing, establishing and maintaining an adequate system of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with Canadian GAAP. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Our management, with the participation of our President and the Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2011 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting, as defined by NI 52-109, is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the President and Chief Financial Officer, we have evaluated changes in internal control over financial reporting that occurred during the fiscal quarter and year ended December 31, 2011 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Our Board of Directors reviewed and approved the 2011 audited consolidated financial statements and this management's discussion and analysis prior to its release.

CRITICAL ACCOUNTING POLICIES & ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Union Gas' operations change and accounting guidance is issued. Union Gas has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Union Gas discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the Board of Directors.

Regulatory Accounting

Union Gas continues to follow Canadian GAAP until January 1, 2012, when Union Gas switches to U.S. GAAP. Canadian GAAP allows accounting treatments that may differ for rate-regulated operations from those otherwise expected in non rate-regulated businesses. As a result, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under Canadian GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to ratepayers. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other rate-regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate and is subject to change in the future. If future recovery of costs ceases to be probable, asset write-offs could be required to be recognized in current period earnings.

Unbilled Revenue

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. Gas sales and distribution revenue and cost of gas are recorded on the basis of regular meter readings and estimates of the unbilled customer usage. The unbilled estimate covers the period of the last meter reading date to the end of each month and is calculated using the number of days unbilled, heating degree-days and historical consumption per heating degree-day. Unbilled revenue recorded at December 31, 2011 was $116 million (2010 – $118 million). Differences between actual and estimated unbilled revenues are not material to net income. Included in unbilled revenue are natural gas costs passed through to customers without a mark-up. At December 31, 2011 $74 million (2010 – $73 million) was included in unbilled revenue for the cost of natural gas.

Employee Future Benefits

Critical estimates and assumptions are required to account for employee future benefits and changes to these estimates and assumptions could result in a material difference to our employee future benefit plan obligation.

The following is a summary of the sensitivity of key assumptions used to record the employee future benefit liability:

Sensitivity of key assumptions

($millions)	**Registered Pension Plan and Supplemental Pension Arrangements**		**Other Post-Retirement Benefits**	
Assumed change in:	**1% Increase**	**1% Decrease**	**1% Increase**	**1% Decrease**
Discount rate				
Change in 2011 net benefit cost	**(7)**	7	**(1)**	1
Change in benefit obligations	**(83)**	93	**(10)**	11
Health care cost trend rate				
Change in 2011 net benefit cost	**N/A**	N/A	**1**	(1)
Change in benefit obligations	**N/A**	N/A	**8**	(7)
Expected rate of return on assets				
Change in 2011 net benefit cost	**(5)**	5	**N/A**	N/A

ACCOUNTING CHANGES

New Accounting Pronouncements – 2011

The Canadian Institute of Chartered Accountants (CICA) issued Section 1601, Consolidated Financial Statements and Section 1602, Non-controlling Interests in January 2009, to be implemented in January 2011. Sections 1601 and 1602 require all entities to report non-controlling interests in subsidiaries as equity on the Consolidated Balance Sheet. In addition, Section 1602 requires entities to report net income and comprehensive income for both the controlling and non-controlling interests. We adopted Section 1601 prospectively and Section 1602 retrospectively as required. The Consolidated Financial Statements and related information in this report, reflect the application of the reporting requirements of Sections 1601 and 1602.

Conversion to U.S. GAAP

In February 2008, the Accounting Standards Board (AcSB) of the CICA confirmed that publicly accountable enterprises would be required to adopt International Financial Reporting Standards (IFRS) in place of GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

In September 2010, the AcSB decided to offer an optional one year deferral for adopting IFRS for qualifying entities with rate regulated activities and permit such entities to continue to apply Part V – Pre-changeover accounting standards of the CICA Handbook during that period. Union Gas is a qualifying entity for purposes of this deferral.

While our IFRS conversion project was on track to meet the original conversion deadline, we have elected to use the deferral offered by the AcSB. This decision was made to allow us to convert at the same time as many companies in our industry, and to review our options, including the adoption of U.S. GAAP instead of IFRS.

In the third quarter of 2011, the securities regulators approved our election to report under U.S. GAAP instead of IFRS for financial years commencing on January 1, 2012, but before January 1, 2015.

Conversion plan

Throughout 2011 we have captured comparative figures and converted to U.S. GAAP on January 1, 2012. Employee training was provided throughout the year and will continue beyond the conversion process. As our parent prescribes to U.S. GAAP, the conversion to U.S. GAAP did not have a significant impact on our financial systems and business activities.

Key accounting differences

The main area of difference in reporting under U.S. GAAP is employee future benefits accounting. We recorded a charge to accumulated other comprehensive income and recognized a regulatory asset in the opening consolidated balance sheet upon conversion to U.S. GAAP primarily as a result of actuarial losses to be recognized under U.S. GAAP.

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas' system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the consolidated financial statements.

The Board of Directors meets regularly with management, the internal auditors and the shareholders' auditors to review the consolidated financial statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board of Directors, as does the Director of Internal Audit Services.

Deloitte & Touche LLP performed an independent audit of the 2011 and 2010 consolidated financial statements in this report. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Independent Auditor's Report.

March 21, 2012

Stephen W. Baker
President

J. Patrick Reddy
Chief Financial Officer

Deloitte & Touche LLP
One London Place
255 Queens Ave
Suite 700
London ON N6A 5R8
Canada

Tel: 519-679-1880
Fax: 519-640-4625
www.deloitte.ca

Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying consolidated financial statements of Union Gas Limited, which comprise the consolidated balance sheets as at December 31, 2011 and December 31, 2010, and the consolidated statements of income and comprehensive income, retained earnings, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Part V Pre-Changeover Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

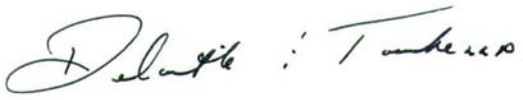
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2011 and December 31, 2010 and the results of its operations and its cash flows for the years then ended in accordance with Part V Pre-Changeover Canadian generally accepted accounting principles.



Chartered Accountants
Licensed Public Accountants
March 21, 2012

UNION GAS LIMITED
Consolidated Statements of Income and Comprehensive Income

For the Years Ended December 31 ($millions)	**2011**	2010
Gas sales and distribution revenue	**1,468**	1,493
Cost of gas (note 15)	**755**	794
Gas distribution margin	**713**	699
Storage and transportation revenue (note 15)	**311**	308
Other revenue	**34**	29
	1,058	1,036
Expenses		
Operating and maintenance (note 15)	**379**	364
Depreciation and amortization	**205**	200
Property and capital taxes	**61**	67
	645	631
Income before interest and income taxes	**413**	405
Interest expense (notes 6 and 15)	**152**	158
Income before income taxes	**261**	247
Income taxes (note 14)	**60**	41
Net income and comprehensive income	**201**	206
Preference share dividends	**2**	2
Net income and comprehensive income applicable to common shares	**199**	204

(*See accompanying notes)*

UNION GAS LIMITED
Consolidated Statements of Retained Earnings

For the Years Ended December 31 ($millions)	**2011**	2010
Retained earnings, beginning of year	**710**	696
Net income and comprehensive income	**201**	206
Dividends		
Preference shares	**(2)**	(2)
Common shares	**(145)**	(190)
Retained earnings, end of year	**764**	710

(*See accompanying notes)*

UNION GAS LIMITED
Consolidated Balance Sheets

As at December 31 ($millions)	**2011**	2010
Assets		
Current assets		
Cash and cash equivalents	**2**	12
Accounts receivable (notes 3 and 15)	**533**	516
Inventories (note 4)	**263**	174
Future income taxes (note 14)	**7**	14
Total current assets	**805**	716
Property, plant and equipment (note 5)		
Cost	**6,615**	6,370
Accumulated depreciation	**2,120**	1,994
Net property, plant and equipment	**4,495**	4,376
Regulatory and other assets (note 13)	**545**	493
Total Assets	**5,845**	5,585
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 15)	**99**	198
Commercial paper (note 6)	**279**	157
Accounts payable and accrued charges (notes 3 and 15)	**618**	586
Income taxes payable (note 14)	**53**	8
Long-term debt (note 6)	**–**	250
Total current liabilities	**1,049**	1,199
Long-term liabilities		
Long-term debt (note 6)	**2,277**	1,978
Mandatorily redeemable preference shares (note 7)	**5**	5
Future income taxes (note 14)	**383**	361
Asset retirement obligations (note 9)	**134**	123
Regulatory and other liabilities (note 13)	**492**	468
Total long-term liabilities	**3,291**	2,935
Total Liabilities	**4,340**	4,134
Equity		
Share capital (note 8)	**732**	732
Retained earnings	**764**	710
Non-controlling interest	**9**	9
Total Equity	**1,505**	1,451
Total Liabilities and Equity	**5,845**	5,585

(See accompanying notes)

Approved by the Board

Director Director

UNION GAS LIMITED
Consolidated Statements of Cash Flows

For the Years Ended December 31 ($millions)	**2011**	2010
Operating Activities		
Net income	**201**	206
Items not affecting cash		
Depreciation and amortization	**205**	200
Future income taxes	**8**	25
Changes in working capital		
Accounts receivable	**(15)**	(42)
Inventories	**(85)**	32
Account payables, accrued charges and other	**40**	(247)
	354	174
Investing Activities		
Capital expenditures	**(290)**	(232)
Financing Activities		
Net increase (decrease) in short-term borrowings	**(99)**	198
Net increase in commercial paper	**122**	118
Long-term debt issued	**300**	250
Long-term debt repayments	**(250)**	(222)
Dividends paid	**(147)**	(308)
	(74)	36
Change in cash and cash equivalents, during the year	**(10)**	(22)
Cash and cash equivalents, beginning of year	**12**	34
Cash and cash equivalents, end of year	**2**	12
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest	**154**	152
Cash payments of income taxes	**8**	96

(See accompanying notes)

UNION GAS LIMITED
Notes to Consolidated Financial Statements
December 31, 2011 and 2010

Union Gas Limited (Union Gas or the Company) owns and operates natural gas transmission, distribution and storage facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the transportation, storage and distribution of natural gas. In total, the Company has approximately 4,700 kilometres of high-pressure transmission pipeline and approximately 62,700 kilometres of distribution main and service pipelines. The Company's underground natural gas storage facilities have a working capacity of more than 155 billion cubic feet (Bcf).

1. Significant Accounting Policies

Accounting Principles

The consolidated financial statements of the Company have been prepared in accordance with Part V – Pre-changeover Canadian generally accepted accounting principles (GAAP) and certain transactions have been recorded using accounting principles for rate-regulated enterprises as discussed below under "Regulation." The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual amounts could differ from these estimates. Management's significant estimates include unbilled revenue, income tax expense, employee future benefit expense, estimated useful life of property, plant and equipment and asset retirement obligations.

Accounting Changes

Consolidated Financial Statements and Non-controlling Interest

The Canadian Institute of Chartered Accountants (CICA) issued Section 1601, Consolidated Financial Statements and Section 1602, Non-controlling Interests in January 2009 under Part V of the CICA handbook, to be implemented in January 2011. Sections 1601 and 1602 require all entities to report non-controlling interests in subsidiaries as equity on the Consolidated Balance Sheet. In addition, Section 1602 requires entities to report net income and comprehensive income for both the controlling and non-controlling interests. The Company adopted Section 1601 prospectively and Section 1602 retrospectively as required. The Consolidated Financial Statements and related information in this report, reflect the application of the reporting requirements of Sections 1601 and 1602.

Conversion to Generally Accepted Accounting Principles of the United States of America (U.S. GAAP)

In February 2008, the Accounting Standards Board (AcSB) of the CICA confirmed that publicly accountable enterprises would be required to adopt International Financial Reporting Standards (IFRS) in place of GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

In September 2010, the AcSB decided to offer an optional one year deferral for adopting IFRS for qualifying entities with rate regulated activities and permit such entities to continue to apply Part V – Pre-changeover accounting standards of the CICA Handbook during that period. Union Gas is a qualifying entity for purposes of this deferral.

We elected to use the deferral offered by the AcSB. This decision was made to allow us to convert at the same time as many companies in our industry, and to review our options, including the adoption of U.S. GAAP instead of IFRS.

In the third quarter of 2011, the securities regulators approved our election to report under U.S. GAAP instead of IFRS for financial years commencing on January 1, 2012, but before January 1, 2015. Effective January 1, 2012, we converted to U.S. GAAP.

Principles of Consolidation

The consolidated financial statements of the Company include the accounts of Union Gas and its subsidiary, Huron Tipperary Limited Partnership I, of which the Company owns 75%.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act* (1998), which is part of a package of legislation known as *The Energy Competition Act* (1998). This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, with the exception of the items noted below, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within Union Gas and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecast revenues and manage costs.

Rates effective January 1, 2007 were approved by the OEB on the basis of the traditional cost of service framework. Effective January 1, 2008, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The Company has applied to set rates for 2013 on a cost of service basis.

The Company follows Canadian GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred, or for certain net revenues beyond a pre-established threshold. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred in either accounts receivable or accounts payable and accrued charges for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings above an allowable return on equity are shared with ratepayers. A provision of $17 million was recognized as a reduction of gas sales and distribution revenue and as an obligation in accounts payable and accrued charges for 2011 (2010 – $4 million).

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

The asset and liability method of tax allocation is used in the accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for differences between the financial reporting and tax basis of assets and liabilities at enacted, or the substantively enacted, tax rates in effect for the years in which the differences are expected to reverse.

Inventories

Gas in storage for resale to customers is carried at costs approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred in either accounts receivable or accounts payable and accrued charges for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment are carried at cost which includes all direct costs, overhead attributable to construction and interest capitalized during construction. The cost of property, plant and equipment is reduced by contributions and grants in aid of construction received from customers and governmental bodies in support of specific transmission and distribution facilities.

Regulated depreciation is provided on the straight-line method at various rates based on the average service life of each class of property. Unregulated depreciation rates are based on useful life.

Regulated depreciation rates are determined by periodic review. The depreciation rates for regulated property, plant and equipment are approved by the OEB. Unregulated depreciation rates are determined by management.

When Union Gas retires regulated property, plant and equipment, the Company charges the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization. When the Company sells entire regulated operating units, or retires non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the OEB.

Asset Retirement Obligations

The Company recognizes the fair value of an asset retirement obligation (ARO), where a legal obligation exists, as a liability in the period in which it is incurred provided a reasonable estimate of fair value can be determined.

The associated asset retirement cost is added to the carrying amount of the related asset. The liability is accreted over the estimated life of the related asset.

Stock-Based Compensation

Our employees participate in a stock-based compensation plan sponsored by Spectra Energy Corp (Spectra Energy). For employee awards, equity classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is measured at the grant date based on the current stock price and re-measured at each reporting period until settlement. The compensation cost is recognized as expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible. Awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

In addition, certain of our employees that previously participated in our 1989 Long Term Incentive Share Plan have the ability to receive a portion of their converted stock option awards as a stock appreciation right (SAR) paid in cash. Union Gas accounts for these by measuring the amount by which the quoted market price of the underlying stock exceeds the SAR base stock price at the balance sheet date.

Employee Benefit Plans

The Company uses the projected benefit method prorated on services to account for defined benefit pension and other post-retirement benefits earned by employees.

The Company accrues obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value. The calculation of the expected return on assets is based on the market-related value of assets with the market related adjustment determined over a three-year period.

Past service costs from plan amendments are amortized on a straight-line basis over the expected average remaining service lifetime of employees active at the date of amendment.

The amount by which the net unamortized cumulative actuarial gain or loss exceeds ten percent of the greater of the accrued benefit obligation or the market-related value of plan assets at the beginning of the year is amortized over the expected average remaining service lifetime of active employees.

The average remaining service period of active employees covered by the pension plans and the other post-retirement benefit plans is 10 and 18 years, respectively.

For defined contribution plans maintained by the Company, contributions payable by the Company are expensed as pension costs in the period incurred.

2. Financial Statement Effects of Rate Regulation

The Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	Recovery/ Settlement Period	**December 31 2011**	December 31 2010
Assets				
Other deferrals – current	a	A	**28**	12
Storage deferrals	a	A	**5**	–
Gas in storage inventory	b	A	**54**	28
Other deferrals – long-term	c	B	**1**	3
Future income taxes – long-term	c	B/C	**235**	214
Total assets			**323**	257
Liabilities				
Other deferrals – current	d	A	**30**	31
Gas cost deferrals	d	A	**54**	39
Storage deferrals	d	A	**12**	9
Asset removal costs	e	C	**427**	409
Total liabilities			**523**	488

In the absence of rate regulation, the Company's future income tax asset (current) would have been $16 million lower in 2011 (2010 - $20 million lower), and the future income tax liability (long-term) would have been $48 million higher in 2011 (2010 - $48 million higher) as a result of the elimination of the above regulatory assets and liabilities.

Financial Statement Classification

(a) Accounts receivable
(b) Inventories
(c) Regulatory and other assets
(d) Accounts payable and accrued charges
(e) Regulatory and other liabilities

Recovery/Settlement Period

(A) Remaining recovery / settlement is less than 1 year
(B) Remaining recovery / settlement is from 2 to 10 years
(C) Remaining recovery / settlement is over the remaining life of the associated assets

Other deferrals – current

As prescribed by regulatory order, the Company has various amounts included in customer rates that are intended to recover specifically-identified costs. To the extent that the actual costs differ from forecast costs or revenues, the variance is deferred for future recovery from or refund to ratepayers. In the absence of rate regulation, after-tax earnings for 2011 could have been $12 million lower (2010 – $3 million higher) because GAAP for non-regulated entities would require that all customer rate revenue and costs be recognized in income when earned.

Storage deferrals

The Company earns revenue for providing storage services to customers. The forecast of this revenue is one component used to establish Union Gas' rates for services. Storage deferral accounts accumulate any difference

between the actual revenue earned in providing these storage services and the forecast revenue approved by the OEB for ratemaking purposes. In the absence of rate regulation, GAAP for non-regulated entities would require that actual storage revenue be recognized in income when earned. After-tax earnings for 2011 could have been $2 million lower (2010 – $8 million lower), if these transactions were accounted for under GAAP for non-regulated entities.

Gas in storage

Gas in storage is carried at the weighted average cost of gas as approved by the OEB. In the absence of rate regulation, after-tax earnings for 2011 could have been $26 million lower (2010 – $9 million higher), because GAAP for non-regulated entities would require that gas in storage be recorded at the lower of cost and net realizable value.

Future income taxes

The accounting standard related to income taxes requires rate-regulated enterprises to recognize future income tax assets and liabilities, and an associated regulatory asset or liability, if applicable, for the amount of future income taxes expected to be recovered from or refunded to ratepayers, and to present these amounts on a gross basis in the financial statements. In the absence of rate regulation, after-tax earnings for 2011 could have been $16 million lower (2010 – $30 million lower) because GAAP for non-regulated entities would require that these amounts be recognized in earnings in the current period.

Gas cost deferrals

The Company and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis, to ensure that customers' rates reflect future expected costs based on published forward market prices. The difference between the approved and the actual cost of gas incurred is deferred for future recovery from or repayment to customers. These deferred amounts are subject to review and approval by the OEB on an annual basis in the normal course. The regulatory asset or liability represents the difference between actual gas commodity costs incurred and the amount included in approved rates. In the absence of rate regulation, after-tax earnings for the 2011 could have been $11 million higher (2010 – $101 million lower), because GAAP for non-regulated entities would require that actual commodity costs be recognized as an expense when incurred.

Asset removal costs

The Company has recorded a regulatory liability, as a result of estimated removal costs for property that does not have an associated legal retirement obligation. In the absence of rate regulation, these costs may not have been recorded and after-tax earnings for 2011 could have been $13 million higher (2010 – $8 million higher).

Property, plant and equipment

In the absence of rate regulation, property, plant and equipment may not include overhead costs, accretion of asset retirement obligations, asset removal costs and gain/loss on retirement or sale of depreciable assets since these costs may have been charged to earnings in the period in which they occurred. As such, annual operating and maintenance costs, interest expense, gain/loss on disposal of assets and depreciation could have been impacted by the amounts capitalized. These amounts are not readily determinable.

3. Gas Imbalances

The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the balance sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2011 accounts receivable and accounts payable include approximately $195 million (2010 – $194 million) related to gas imbalances and gas balancing services.

4. Inventories

($millions)	**December 31 2011**	December 31 2010
Gas in storage	**247**	157
Materials and supplies	**16**	17
	263	174

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are used in the operation and maintenance of the Company's system.

5. Net Property, Plant and Equipment

($millions)	**December 31 2011**	December 31 2010
Cost		
Distribution	**3,729**	3,594
Transmission	**1,706**	1,639
Storage	**913**	870
General	**267**	267
	6,615	6,370
Accumulated depreciation		
Distribution	**1,143**	1,086
Transmission	**567**	498
Storage	**305**	277
General	**105**	133
	2,120	1,994
Net book value	**4,495**	4,376

The depreciation range of each class of property is as follows:

Distribution	27-60 years
Transmission	30-50 years
Storage	5-50 years
General	4-38 years

Depreciation rates used during the year ended December 31, 2011 resulted in a composite rate of 3.25% (2010 – 3.26%).

Included in property, plant and equipment are the following:

($millions)	**December 31 2011**	December 31 2010
Assets not subject to depreciation[13]	**147**	161
Asset retirement cost	**41**	35
Interest charge capitalized during the year	**3**	1

[13] Assets not subject to depreciation include land, base pressure gas in storage reservoirs and assets under construction.

6. Debt and Credit Facility

Long-term Debt

		December 31	December 31
($millions)		**2011**	2010
6.65%	Series 3, redeemed May, 2011	**–**	250
7.90%	1994 Series debentures, due February 24, 2014	**150**	150
11.50%	1990 Series debentures, due August 28, 2015	**150**	150
4.64%	Series 5, due June 30, 2016	**200**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
4.85%	Series 7, due April 25, 2022	**125**	125
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	–
		2,290	2,240
Less: deferred financing charges		**13**	12
		2,277	2,228
Less: current portion		**–**	250
		2,277	1,978

The Company's long-term debt is unsecured. The weighted average cost of long-term debt as at December 31, 2011 was 6.6% (2010 – 6.8%). Principal repayment requirements on long-term debt are as follows:

($millions)	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt	2,290	–	–	150	150	200	1,790

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2011 and 2010, the Company is in compliance with all such covenants.

Total interest paid on long-term debt in 2011 was $151 million (2010 – $150 million).

Available Credit Facility and Restrictive Debt Covenants

	Expiration Date	**Credit Facility Capacity**	**Outstanding at December 31, 2011 Commercial Paper**
Multi-year syndicated[14]	2016	400	279

The issuance of commercial paper and other facility borrowings reduces the amount available under the credit facility.

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in

[14] Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year.

accelerated due dates and/or termination of the agreement. As of December 31, 2011, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries.

A majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2011 was 1.05% (2010 – 1.05%).

Total interest paid on short-term debt in 2011 was $3 million (2010 – $2 million).

7. Mandatorily Redeemable Preference Shares

		Outstanding at			
Authorized		**December 31 2011**	December 31 2010	**December 31 2011**	December 31 2010
(shares)		*(shares)*		*($millions)*	
Class A – 112,072	Series A, 5.5%	**47,672**	47,672	**3**	3
	Series C, 5.0%	**49,500**	49,500	**2**	2
				5	5

The Class A, Series A and C Preference Shares are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

8. Share Capital

		Outstanding at			
	Authorized	**December 31 2011**	December 31 2010	**December 31 2011**	December 31 2010
	(shares)	*(shares)*		*($millions)*	
Preference shares:					
Class A, Series B, 6%	90,000	**90,000**	90,000	**5**	5
Class B, Series 10, 4.88%	Unlimited	**4,000,000**	4,000,000	**100**	100
				105	105
Common Shares	Unlimited	**57,822,650**	57,822,650	**627**	627
				732	732

The Class A, Series B Preference Shares are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preference Shares are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares every five years commencing January 1, 2014. Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2013.

9. Asset Retirement Obligation

The Company has a legal obligation to disconnect, purge and cap abandoned pipeline, as well as capping abandoned storage wells. The Company also has buildings that contain asbestos and therefore will have a legal obligation requiring the special handling and disposition of the asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term. The Company has determined that sufficient information to estimate the fair value of an ARO is not available because the assets are considered permanent with indeterminate useful lives and that sufficient information is not available to estimate a range of potential settlement dates in order to employ a present value technique to estimate fair value.

At December 31, 2011, the estimated undiscounted cash flows required to settle our AROs was $618 million (2010 – $587 million), calculated using an inflation rate of 2.9% per annum (2010 – 2.0%). The estimated fair value of this liability was $134 million (2010 – $123 million). The estimated cash flows of new obligations incurred during the year have been discounted at a rate of 3.08% per annum (2010 – 3.80%). At December 31, 2011, the timing of payment for settlement of the obligations ranges from 1 to 147 years.

Reconciliation of Asset Retirement Obligations:

($millions)	**December 31 2011**	December 31 2010
Balance, beginning of year	**123**	108
Liabilities incurred	**5**	10
Liabilities settled	**–**	(1)
Accretion	**6**	6
Balance, end of year	**134**	123

10. Stock-Based Compensation

Under the Long Term Incentive Share Option Plan 1989 (1989 Plan), the Company's parent company, Westcoast Energy Inc. (Westcoast) has granted certain stock options to its employees, including employees of Union Gas. Stock options are granted at an exercise price that equals the market price as defined in the 1989 Plan of Westcoast's shares on the date of grant. The 1989 Plan also provides for share appreciation rights under which the holder of a stock option may, in lieu of exercising the option, exercise the share appreciation right.

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 40 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms and generally vest over a three year term. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Spectra Energy issues new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model is used to estimate the fair value of options at grant date.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair value of the shares on the date of grant. Related compensation expense is recognized over the requisite service period which is the same as the vesting period.

At the time of the Spectra Energy spin-off from Duke Energy, Duke Energy converted stock options, restricted stock awards, performance awards and phantom stock awards (collectively, Stock-Based Awards) of Duke

Energy common stock held by Spectra Energy employees and Duke Energy employees. One replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the spin-off. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the 2007 LTIP.

Spectra Energy allocated pre-tax stock-based compensation expense included in continuing operations to Union Gas for 2011 and 2010 as follows, the components of which are further described below:

($millions)	**December 31 2011**	December 31 2010
Phantom Stock	**1**	1
Performance Awards	**2**	1
Total	**3**	2

Stock Options

	Shares	**Weighted-Average Exercise Price US$**
Outstanding at beginning of year	**201,758**	**$25**
Transfers in/(out)	**–**	**–**
Granted	**–**	**–**
Exercised	**(25,007)**	**25**
Forfeited	**(16,636)**	**31**
Outstanding at end of year	**160,115**	**$24**
Options exercisable at year-end	**160,115**	**$24**

	Options Outstanding			**Options Exercisable**	
Exercise Prices US$	Number Outstanding At 12/31/11	Weighted-Average Remaining Contractual Life(in years)	Weighted-Average Exercise Price US$	Number Exercisable At 12/31/11	Weighted-Average Exercise Price US$
$11 – 15	19,450	1.2	$12	19,450	$12
$16 – 20	–	–	–	–	–
$21 – 25	124,300	5.2	25	124,300	25
$26 – 30	8,415	0.1	29	8,415	29
$31 – 37	7,950	0.2	33	7,950	33
> $37	–	–	–	–	–
Total	160,115	4.2	$24	160,115	$24

The Company did not award non-qualified stock options to employees during 2011 or 2010. As of December 31, 2011 all stock options are fully vested.

Performance Awards

Under the 2007 LTIP, the Company can also grant stock-based and cash-based performance awards. The performance awards generally vest over three years at the earliest, if performance metrics are met. The cash-based awards will be settled in cash at vesting. The Company granted 31,800 stock-based awards and 31,800 cash-based awards with fair values of US $1 million for each of the grants to employees during 2011. The Company granted 59,400 stock-based performance awards with a fair value of US $2 million during 2010. The unvested and outstanding performance awards granted contain market conditions based on the total shareholder return (TSR) of Spectra Energy common stock relative to a pre-defined peer group. The stock-based awards are

valued using the Monte Carlo valuation method. The cash-based awards are valued at Spectra Energy's current stock price and are re-measured at each reporting period until settlement.

Weighted-Average Assumptions for Stock-Based Performance Awards

	December 31 2011	December 31 2010
Risk free interest rate	**1.2%**	**1.4%**
Expected life (years)	**3**	**3**
Expected volatility Spectra Energy	**37.7%**	**37.9%**
Expected volatility Peer Group	**21.2-59.6%**	**22.3-58.5%**
Market Index	**30.3%**	**30.3%**
Expected dividend yield	**–**	**–**

The risk-free rate of return was determined based on a yield of three year U.S. Treasury bonds on the grant date. The expected volatility was established based on historical volatility over three years using daily stock price observations. A shorter period was used if three years of data was not available. Because the award payout includes dividend equivalents, no dividend yield assumption is required.

The total fair value of the performance shares vested was US $1 million in 2011 and none in 2010, as Spectra Energy performance awards were first granted in 2008. As of December 31, 2011, the Company expects to recognize US $2 million of future compensation cost related to stock awards over a weighted-average period of less than two years.

Phantom Stock Awards

Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. The Company awarded 47,200 phantom awards with a fair value of US $1 million during 2011, and 65,600 phantom awards with a fair value of US $1 million during 2010.

The total fair value of the phantom shares vested was US $975,602 in 2011 and US $778,935 in 2010. As of December 31, 2011, the Company expects to recognize US $1 million of future compensation cost related to stock awards over a weighted-average period of less than two years.

11. Capital Management

The Company's objectives in managing its capital include the continuation of its ability to serve customers and to generate the OEB allowed rate of return for its shareholders while maintaining the OEB-approved level of common equity.

In managing capital, management considers both debt and equity. The mix of debt and equity components is driven by prevailing market conditions, as the Company may take advantage of lower interest rates by issuing debt or utilizing available credit facilities. The Company is required by Undertakings to the Lieutenant Governor in Council of Ontario to maintain sufficient common equity at the level approved by the OEB. The quarterly dividend payment is determined to allow the Company to maintain the common equity component at the level approved by the OEB.

Various debt covenants require the Company's Indebtedness[15] not to exceed 75% of Total Capitalization[16].

[15] Indebtedness includes short-term borrowings, commercial paper, long-term debt and mandatorily redeemable preference shares.
[16] Capitalization includes equity and indebtedness.

As at December 31, 2011 and 2010, the Company was in compliance with the following externally imposed capital requirements. The Company monitors these requirements on a quarterly basis.

	December 31 2011	December 31 2010
OEB-approved minimum Common Equity	**36.00%**	36.00%
Allowed Return on Equity – regulated operations	**8.54%**	8.54%
Maximum Total Indebtedness to Total Capitalization	**75.00%**	75.00%
Actual Total Indebtedness to Total Capitalization	**63.90%**	64.10%

12. Financial Instruments

Under Canadian GAAP, financial instruments are classified into one of the following five categories: held-for trading, held to maturity investments, loans and receivables, available-for-sale financial assets and other financial liabilities.

The carrying value of the Company's financial instruments are classified into the following categories:

Classification

($millions)	**December 31 2011**	December 31 2010
Financial assets held for trading[17]	**2**	12
Loans and receivables[18]	**296**	301
Other financial liabilities[19]	**2,889**	2,793

The fair values of the Company's financial instruments are not materially different from their carrying value, with the exception of the Company's long-term debt of $2,290 million (2010 – $2,240 million). Based on current interest rates for debt with similar terms and maturities, the fair market value is estimated to be $2,849 million (2010 – $2,610 million).

Fair value hierarchy

Financial instruments recorded at fair value on the Consolidated Balance Sheet are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices);

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

Cash and cash equivalents are the only financial instruments recorded at fair value on the Consolidated Balance Sheet and are classified as level 1.

[17] Includes cash and cash equivalents
[18] Includes trade and other receivables
[19] Includes accounts payable and accrued charges, short-term borrowings, commercial paper, long-term debt, and mandatorily redeemable preference shares

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The long-term debt bears interest at fixed rates and therefore the cash flow exposure is not significant. However, the fair value of loans having fixed rates of interest could fluctuate because of changes in market interest rates. The fair value of short-term borrowings has a limited exposure to interest rate risk due to their short-term maturity.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligation. The maximum exposure to credit risk of the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement amount of gas loans at December 31, 2011 is $64 million receivable (2010 - $72 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on accounts receivable, the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2011 amounted to $48 million (2010 - $51 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

Union Gas continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31 2011**	December 31 2010
Current	**263**	284
30 Days over due	**10**	9
60 Days over due	**4**	3
90+ Days over due	**7**	6
Total trade accounts receivable	**284**	302
Allowance for doubtful accounts	**(4)**	(5)
Total trade accounts receivable, net[20]	**280**	297

For the years ended December 31, 2011 and 2010, no one customer accounted for more than 10% of sales or 10% of receivables.

Equity Price Risk

Our costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon, among other things, rates of return on plan assets. These plan assets expose us to price fluctuations in equity markets. In addition, our captive insurance company maintains various investments to

[20] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

fund certain business risks and losses. Those investments may, from time to time, include investments in equity securities. Currently, we do not invest in equity securities other than employee benefits plan assets.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 6).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2011:

($millions)	Total	2012	2013–2014	2015–2016	Thereafter
Short-term borrowings	99	99	–	–	–
Commercial paper	279	279	–	–	–
Accounts payable and accrued charges	618	618	–	–	–
Long-term debt (including principal and interest)	4,397	150	441	599	3,207
Mandatorily redeemable preference shares	5	–	–	–	5
Total	5,398	1,146	441	599	3,212

13. Employee Future Benefits

The Company sponsors five registered defined benefit pension plans and one registered pension plan with both a defined benefit provision and a defined contribution provision. Our eligible employees participate in one of these registered pension plans. All of the defined benefit plans provide a final average earnings related benefit. The Company makes contributions to the defined contribution plan based on the salary, age and service of each member. Supplemental defined benefit pensions are provided to all employees affected by the maximum pension limits under the Income Tax Act. Other post-retirement benefits provided include health and dental benefits, life insurance coverage and a health care spending account.

Accrued benefit obligations are determined using the projected benefit method pro-rated on services. The Company uses a measurement date of September 30. In determining the accrued benefit obligations and current service costs, the Company uses Management's best-estimate assumptions, except for the liability discount rate, which is determined as the yield on high quality fixed income investments with a term to maturity similar to the covered benefits.

Plan assets are valued at fair value. The calculation of the expected return on assets is based on a market related value of assets, with the market related adjustment determined over a three-year period.

The transitional obligation associated with the change in accounting for Employee Future Benefits at January 1, 2000 is being amortized on a straight line basis over the expected average remaining service lifetime (EARSL) of employees active at January 1, 2000. Past service costs arising from plan amendments are amortized on a straight-line basis over the EARSL of employees active at the date of the amendment. The amount by which the net unamortized cumulative actuarial gain or loss based on the market related value of assets exceeds 10% of the greater of the accrued benefit obligation and the market related value of assets at the beginning of the period is amortized on a straight-line basis over the EARSL of employees active at the beginning of the period. The average remaining service period of the active employees covered by the retirement plans is 10 years. The average remaining service period of the active employees eligible for other post-retirement benefits is 18 years.

The Company made the following employee future benefit contributions:

($millions)	**December 31 2011**	December 31 2010
Defined benefit plans	**88**	40
Defined contribution pension plan	**5**	5
Supplemental pension	**1**	1
Other post-retirement benefits	**3**	2
	97	48

Actuarial Valuations

	Pension Benefit Plans	**Other Post-Retirement Benefits**
Most recent	January 1, 2011	January 1, 2009
Next scheduled	January 1, 2012	January 1, 2012

Benefit Obligations, Plan Assets and Funded Status

	Years Ended December 31			
	Pension		Other	
($millions)	**2011**	2010	**2011**	2010
Change in benefit obligations				
Balance, beginning of year	**655**	585	**69**	60
Employer current service cost	**12**	11	**2**	2
Member contributions	**3**	3	**–**	–
Interest cost	**33**	34	**4**	3
Benefits paid	**(31)**	(30)	**(3)**	(2)
Past service cost	**–**	7	**–**	–
Actuarial loss	**42**	45	**5**	6
Balance, end of year	**714**	655	**77**	69
Change in fair value of assets				
Fair value, beginning of year	**503**	443	**–**	–
Actual return on plan assets	**–**	45	**–**	–
Employer contributions	**38**	42	**3**	2
Member contributions	**3**	3	**–**	–
Benefits paid	**(31)**	(30)	**(3)**	(2)
Fair value, end of year	**513**	503	**–**	–
Funded status				
Net funded status	**(201)**	(152)	**(77)**	(69)
Unamortized net actuarial loss	**313**	258	**21**	17
Unamortized past service costs	**10**	12	**–**	–
Unamortized transitional obligation	**5**	6	**7**	8
Contributions remitted after measurement date	**61**	10	**–**	–
Accrued benefit asset (liability), end of year	**188**	134	**(49)**	(44)
Classification of accrued benefit assets (liabilities)				
Regulatory and other assets	**208**	152	**–**	–
Accounts payable and accrued charges	**(1)**	(1)	**(3)**	(3)
Regulatory and other liabilities	**(19)**	(17)	**(46)**	(41)
Accrued benefit asset (liability)	**188**	134	**(49)**	(44)
Allocation of assets to major classes				
Equity securities	**49%**	54%	**–**	–
Debt securities	**50%**	46%	**–**	–
Cash and cash equivalents	**1%**	–	**–**	–

For 2011 and 2010, all of the defined benefit pension plans had accrued benefit obligations that exceeded the fair value of plan assets. The other post-retirement benefit plans are not pre-funded.

Net benefit cost

	Years Ended December 31			
	Pension		Other	
($millions)	**2011**	2010	**2011**	2010
Current service cost	**12**	11	**2**	2
Interest cost	**33**	34	**4**	3
Actual return on plan assets	**–**	(45)	**–**	–
Actuarial losses	**42**	45	**5**	6
Past service cost	–	7	**–**	–
Elements of employee future benefits costs before adjustments to recognize the long-term nature of employee future benefit costs	**87**	52	**11**	11
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return	**(34)**	11	**–**	–
Difference between actual and recognized actuarial gains in year	**(21)**	(31)	**(4)**	(6)
Difference between actual and recognized past service costs in year	**2**	(5)	**–**	–
Amortization of transitional obligation	**1**	1	**1**	2
Defined benefit costs recognized	**35**	28	**8**	7
Defined contribution cost	**5**	5	**–**	–
Total net benefit cost	**40**	33	**8**	7

Weighted average assumptions used to determine benefit liability

	Years Ended December 31			
	Pension		Other	
	2011	2010	**2011**	2010
Discount rate at measurement date	**4.60%**	5.04%	**4.64%**	5.11%
Rate of compensation increase	**3.25%**	3.25%	**3.25%**	3.25%
Initial overall health care trend rate	**–**	–	**7.50%**	8.00%
Annual rate of decline in health care trend rate	**–**	–	**0.50%**	0.50%
Ultimate health care cost trend rate	**–**	–	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**–**	–	**2017**	2017

Weighted average assumptions used to determine net benefit cost

	Years Ended December 31			
	Pension		Other	
	2011	2010	**2011**	2010
Discount rate	**5.04%**	5.62%	**5.11%**	5.69%
Expected rate of return on plan assets	**7.00%**	7.00%	**–**	–
Rate of compensation increases	**3.25%**	3.50%	**3.25%**	3.50%
Initial overall health care trend rate	**–**	–	**8.00%**	8.00%
Annual rate of decline in health care trend rate	**–**	–	**0.50%**	0.50%
Ultimate health care cost trend rate	**–**	–	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**–**	–	**2017**	2016

Sensitivity of key assumption

($millions)	Other Post-Retirement Benefits	
Assumed change in health care cost trend rate	**1% Increase**	**1% Decrease**
Change in obligation	**8**	**(7)**

14. Income Taxes

The provision for income taxes consists of the following:

($millions)	**December 31 2011**	December 31 2010
Current	**52**	16
Future	**8**	25
	60	41

The year-over-year change in the components of current and future income taxes is primarily due to the difference in the treatment of the approved cost and the actual cost of gas for income tax and accounting purposes.

Net income taxes paid in 2011 were $8 million (2010 - $96 million).

Reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

($millions)	**December 31 2011**	December 31 2010
Income before income taxes	**261**	247
Statutory income tax rate (percent)	**28.25**	31.0
Statutory income tax rate applied to accounting income	**74**	77
Increase/(decrease) resulting from:		
Future tax recovery resulting from tax rate changes	**–**	(4)
Future regulatory income tax payable/receivable recorded through tax expense	**(19)**	(32)
Other – net	**5**	–
Provision for income taxes	**60**	41
Effective rate of income tax (percent)	**23.0**	16.6

The future income taxes recorded in current assets of $7 million (2010 – $14 million) arise from temporary differences primarily related to regulatory deferral accounts.

The long-term future income tax liability of $383 million (2010 - $361 million) includes the following:

($millions)	**December 31 2011**	December 31 2010
Temporary differences related to pension asset	**38**	26
Temporary differences related to accelerated depreciation rates	**345**	335
	383	361

15. Related Party Transactions

The Company purchases gas, storage and transportation services at prevailing market prices and under normal trade terms from related parties. During the year ended December 31, 2011, these purchases totalled $56 million (2010 – $11 million). Union Gas also provides storage and transportation services to related parties which totalled $1 million during 2011 (2010 – $1 million).

The Company provided administrative, management and other services to related parties totalling $12 million (2010 – $10 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $9 million (2010 – $9 million).

At December 31, 2011 the Company had receivable balances of $4 million (2010 – $2 million) and payable balances of $7 million (2010 – $3 million) with related parties, all of which are recorded in accounts receivable and accounts payable, respectively.

During 2011, the Company obtained from and provided unsecured loans to Westcoast. The balance outstanding on these loans at December 31, 2011 was a $99 million payable (2010 – $198 million payable). Interest received on these loans during 2011 totalled less than $1 million (2010 – less than $1 million) and interest paid on these loans totalled less than $1 million (2010 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

16. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheet. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

17. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated. The Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its consolidated financial statements.

DIRECTORS

David G. Unruh

Stephen W. Baker

Bruce E. Pydee

OFFICERS

Stephen W. Baker
Chair and President

J. Patrick Reddy
Chief Financial Officer

M. Richard Birmingham
Vice President, Regulatory and Public Affairs

Bruce E. Pydee
Vice President and General Counsel

Bohdan I. Bodnar
Vice President, Human Resources

Menelaos Ydreos
Vice President, Government and Aboriginal Affairs

Mark J. Isherwood
Vice President, Business Development – Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael P. Shannon
Vice President, Distribution Operations

Joe R. Martucci
Vice President, Finance

Guy G. Buckley
Vice President and Treasurer

Timothy J. Kennedy
Vice President, Federal Government Affairs

Paul K. Haralson
Assistant Treasurer

Patricia M. Rice
Corporate Secretary

Leigh A. Hodgins
Assistant Secretary

Joseph Marra
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CIBC Mellon**

Union Gas Limited preference shares are listed on the Toronto Stock Exchange
Class A Preference, Series A – 5½% (UNG.PR.C)

Class A Preference, Series B – 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North Chatham, Ontario N7M 5M1

UNION GAS LIMITED
Reconciliation of Statement of Utility Income to Audited Consolidated Income Statement
Calendar Year Ending December 31, 2011

Line No.	Particulars ($ millions)	EB-2012-0087, Exhibit A, Tab 2 Appendix B, Schedule 1, column (a)	Audited Financial Statements	Difference	
		(a)	(b)	(c)	
	Operating Revenues				
1	Operating revenue	1,485	1,468	17	(1)
2	Storage & transportation	310	311	(1)	(2)
3	Other	34	34	-	
4		1,829	1,813	16	
	Operating Expenses				
5	Cost of gas	755	755	-	
6	Operating and maintenance expenses	385	379	6	(3) (2)
7	Depreciation	204	205	(1)	(2)
8	Other financing	-	-	-	
9	Property and capital taxes	62	61	1	(4)
10		1,406	1,400	6	
	Other				
11	Gain / (Loss) on sale of assets	6	-	6	(3)
12	Other / HTLP	(1)	-	(1)	(2)
13	Gain / (Loss) on foreign exchange	1	-	1	(4)
14		6	-	6	
15	Earnings Before Interest and Taxes	429	413	16	

Notes:
(1) 2011 Earnings Sharing Provision.
(2) HTLP activity and rounding.
(3) St. Clair Transmission Line reclassification.
(4) Other income netted with property and capital taxes and rounding.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 2 / Appendix A / Schedule 3
Exhibit A / Tab 1 / Pages 16-17 & 20-21

Preamble: Union has included under column (K) – Adjustments, $0.5 million for its Low Income Program Incentive and $0.244 million for its CDM / HPNC related revenues. Board staff notes that other amounts have been presented elsewhere in the application (Exhibit A, Tab 1, Pages 16 and 17 and Exhibit A, Tab 1, Pages 20 and 21). Board staff notes that differences between the figures are small and likely immaterial, however Board staff would still like clarification as to the correct amounts.

Please reconcile the two adjustments noted above (i.e. Low Income Program Incentive and CDM / HPNC related revenues) from the figures shown in Exhibit A, Tab 1 to the figures cited in Exhibit A, Tab 2, Appendix A, Schedule 3.

Response:

The figures shown in Exhibit A, Tab 2, Appendix A, Schedule 3 are the amounts for Union's Low-income Program Incentive and CDM/HPNC related revenues included in its 2011 Corporate earnings in column (i)

Exhibit A, Tab 1, Schedule 1 includes the amount Union is requesting for disposition.

The difference between the two schedules for the Low-income Program Incentive is a result of the finalization of the 2011 Home Weatherization Scorecard in early 2012. The variance from the estimate recorded in Corporate earnings of $0.044 million will be adjusted in 2012.

The difference between the two schedules for CDM/HPNC program is that the deferral account includes 50% of the 2010 and 2011 program revenue while the Corporate earnings schedule only includes 2011 revenue. The program revenue for 2011 was $0.173 million. The variance from the 2011 estimate recorded in Corporate earnings of $0.071 million will be adjusted in 2012.

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 2 / Appendix A / Schedule 13

Please provide details of the changes in O&M expenses for the following line items included in Exhibit A, Tab 2, Appendix A, Schedule 13 from 2010 (actual) to 2011 (actual):

i. Line 1 – Salaries / Wages;
ii. Line 2 – Benefits;
iii. Line 4 – Employee Training;
iv. Line 5 – Contract Services;
v. Line 13 – Advertising;
vi. Line 18 – Cost Recovery from Third Parties;
vii. Line 21 – Outbound Affiliate Services; and
viii. Line 22 – Inbound Affiliate Services.

Response:

Please see Attachment 1 for variance explanations for all O&M line items as filed in EB-2011-0210.

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Salaries / Wages		
1	2011 Actual	191,837	/u
2	2010 Actual	183,249	
3	Difference	8,588	/u
	Reasons:		
4	Incentive Accrual/Payout	2,500	/u
5	Merit Increase @ 3.0%	5,100	/u
6	Severances	1,100	/u
7	Other	(112)	/u
8	Total difference: 2011 Actual vs. 2010 Actual	8,588	/u
	Benefits		
9	2011 Actual	81,179	/u
10	2010 Actual	70,861	
11	Difference	10,318	/u
	Reasons:		
12	Higher Flex Benefit Costs	1,200	/u
13	Higher Legislated Benefit Costs	800	/u
14	WSIB Refund	(400)	/u
15	Increased Pension Costs	8,800	/u
16	Other	(82)	/u
17	Total difference: 2011 Actual vs. 2010 Actual	10,318	/u
	Materials		
18	2011 Actual	10,701	/u
19	2010 Actual	9,631	
20	Difference	1,070	/u
	Reasons:		
21	Write off of obsolete inventory	1,200	/u
22	Other	(130)	/u
23	Total difference: 2011 Actual vs. 2010 Actual	1,070	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Employee Expenses / Training		
1	2011 Actual	13,514	/u
2	2010 Actual	11,783	
3	Difference	1,731	/u
	Reasons:		
4	Relocation costs	600	/u
5	Meals and accommodation expense	465	/u
6	Mileage and travel expense	530	/u
7	Employee training expense	100	/u
8	Other	36	/u
9	Total difference: 2011 Actual vs. 2010 Actual	1,731	/u
	Contract Services		
10	2011 Actual	63,608	/u
11	2010 Actual	57,335	
12	Difference	6,273	/u
	Reasons:		
13	Pipeline integrity work	2,500	/u
14	Line locate activity higher in 2011	1,500	/u
15	STO Dawn repairs	600	/u
16	Anodes station work	500	/u
17	HR service costs	300	/u
19	Olameter costs	200	/u
19	Other	673	/u
20	Total difference: 2011 Actual vs. 2010 Actual	6,273	/u
	Consulting		
21	2011 Actual	7,713	/u
22	2010 Actual	7,506	
23	Difference	207	/u
	Reasons:		
24	Seismic testing	200	/u
25	Other	7	/u
26	Total difference: 2011 Actual vs. 2010 Actual	207	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	General		
1	2011 Actual	22,262	/u
2	2010 Actual	21,211	
3	Difference	1,051	/u
	Reasons:		
4	HST Deferral	583	/u
5	Increased postage costs in 2011	200	/u
6	Other	268	/u
7	Total difference: 2011 Actual vs. 2010 Actual	1,051	/u
	Transportation and Maintenance		
8	2011 Actual	9,012	/u
9	2010 Actual	7,892	
10	Difference	1,120	/u
	Reasons:		
11	Volume and price	1,120	/u
12	Total difference: 2011 Actual vs. 2010 Actual	1,120	/u
	Company Used Gas		
13	2011 Actual	2,401	/u
14	2010 Actual	2,451	
15	Difference	(50)	/u
	Reasons:		
16	Other	(50)	/u
17	Total difference: 2011 Actual vs. 2010 Actual	(50)	/u
	Utility Costs		
18	2011 Actual	4,069	/u
19	2010 Actual	3,704	
20	Difference	365	/u
	Reasons:		
21	Increased utility costs	365	/u
22	Total difference: 2011 Actual vs. 2010 Actual	365	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Communications		
1	2011 Actual	6,394	/u
2	2010 Actual	6,780	
3	Difference	(386)	/u
	Reasons:		
4	Reductions due to Rogers APN network	(200)	/u
5	Other	(186)	/u
6	Total difference: 2011 Actual vs. 2010 Actual	(386)	/u
	Demand Side Management Programs		
7	2011 Actual	17,925	/u
8	2010 Actual	16,438	
9	Difference	1,487	/u
	Reasons:		
10	DSM program costs	1,487	/u
11	Total difference: 2011 Actual vs. 2010 Actual	1,487	/u
	Advertising		
12	2011 Actual	2,376	/u
13	2010 Actual	1,860	
14	Difference	516	/u
	Reasons:		
15	Notice of rates proceeding	100	/u
16	Customer advertising	270	/u
17	Other	146	/u
18	Total difference: 2011 Actual vs. 2010 Actual	516	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Insurance		
1	2011 Actual	8,101	/u
2	2010 Actual	8,507	
3	Difference	(406)	/u
	Reasons:		
4	Lower Insurance premiums	(406)	/u
5	Total difference: 2011 Actual vs. 2010 Actual	(406)	/u
	Donations		
6	2011 Actual	632	/u
7	2010 Actual	749	
8	Difference	(117)	/u
	Reasons:		
9	Other	(117)	/u
10	Total difference: 2011 Actual vs. 2010 Actual	(117)	/u
	Financial		
11	2011 Actual	1,682	/u
12	2010 Actual	2,077	
13	Difference	(395)	/u
	Reasons:		
14	Other	(395)	/u
15	Total difference: 2011 Actual vs. 2010 Actual	(395)	/u
	Lease		
16	2011 Actual	4,092	/u
17	2010 Actual	3,632	
18	Difference	460	/u
	Reasons:		
19	Other	460	/u
20	Total difference: 2011 Actual vs. 2010 Actual	460	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Cost Recovery from Third Parties		
1	2011 Actual	(5,869)	/u
2	2010 Actual	(4,641)	
3	Difference	(1,228)	/u
	Reasons:		
4	Dawn STO insurance recovery	(600)	/u
5	Goderich tornado insurance recovery	(345)	/u
6	Other insurance recoveries	(283)	/u
7	Total difference: 2011 Actual vs. 2010 Actual	(1,228)	/u
	Computers		
8	2011 Actual	5,287	/u
9	2010 Actual	4,922	
10	Difference	365	/u
	Reasons:		
11	Other	365	/u
12	Total difference: 2011 Actual vs. 2010 Actual	365	/u
	Regulatory Hearing & OEB Cost Assessment		
13	2011 Actual	3,306	/u
14	2010 Actual	3,126	
15	Difference	180	/u
	Reasons:		
16	Other	180	/u
17	Total difference: 2011 Actual vs. 2010 Actual	180	/u
	Outbound Affiliate Services		
18	2011 Actual	(11,697)	/u
19	2010 Actual	(10,182)	
20	Difference	(1,515)	/u
	Reasons:		
21	Other	(1,515)	/u
22	Total difference: 2011 Actual vs. 2010 Actual	(1,515)	/u

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars	($000's)	
	Inbound Affiliate Services		
1	2011 Actual	8,956	/u
2	2010 Actual	9,462	
3	Difference	(506)	/u
	Reasons:		
4	Other	(506)	/u
5	Total difference: 2011 Actual vs. 2010 Actual	(506)	/u
	Bad Debt		
6	2011 Actual	4,455	/u
7	2010 Actual	5,075	
8	Difference	(620)	/u
	Reasons:		
9	WACOG and bad debt experience	(620)	/u
10	Total difference: 2011 Actual vs. 2010 Actual	(620)	/u
	Other		
11	2011 Actual	206	/u
12	2010 Actual	249	
13	Difference	(43)	/u
	Reasons:		
14	Other	(43)	/u
15	Total difference: 2011 Actual vs. 2010 Actual	(43)	/u

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A / Tab 3

a) Please highlight the deferral accounts and other balances for which the allocation methodology proposed by Union have not yet been approved by the Board.

b) For each of these accounts (or other balances), please provide the rationale for the allocation methodology proposed. Please also discuss whether any alternatives to the allocation methodology proposed were considered.

c) For all the accounts (and other balances) where an allocation methodology has been previously approved by the Board, please confirm that the allocation methodology used in this application is the same as the most recently approved allocation methodology.

Response:

a) The two accounts for which the Board has not approved the allocation methodology are the Conservation Demand Management Deferral Account (No. 179-123) and the Low-income Incentive amount.

b) Union proposes to allocate the balance in the Conservation Demand Management ("CDM") deferral account to rate classes in proportion to the DSM amounts in approved 2011 rates. This allocation methodology recognizes that the CDM deferral account balance is not attributable to any specific rate class. The proposed disposition of the CDM deferral account credit to rate classes based on how the costs of similar activities are allocated in approved 2011 rates is appropriate.

Union considered two other allocation methodologies for the disposition of the Conservation Demand Management deferral account.

The first alternative methodology considered was an allocation based on the average number of customers by rate class. This methodology was rejected as it allocated a disproportionate amount of the CDM deferral account balance to general service customers.

The second allocation methodology considered was rate base. This methodology was rejected as a rate base allocation is not reflective of how the costs of similar activities are allocated in approved 2011 rates.

Union has allocated the Incremental Low-income Incentive amount to the Rate 01 and Rate M1 rate classes based on 2011 net volume savings. Union did not consider any other allocation methodologies for this balance as net volume savings were used to allocate the costs of the program.

c) Confirmed. For Union's deferral accounts where the allocations have most recently been approved by the Board in EB-2011-0038 (Union's 2010 Deferral Disposition), the 2011 allocation proposals are consistent with the allocations approved by the Board in that proceeding.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Page 13, Table 2
Exhibit A, Tab 3, Schedule 1, Page 1

Please fill out the Table 1 below in order to show the forecasted and actual spending for each program that impacts rates 20, 100, T1 and M12. Please indicate in column 4 the total spending for each program and not the sum of spending for rates 20, 100 and T1. If the number in column 4 happens to equal the sum of the spending for rates 20, 100 and T1, please add a note indicating that no additional amount was spent on another rate class for that program.

2011 Forecasted DSM spending

Line No.	Program Name	Particulars/Details (e.g., Resource Acquisition, Market Transformation, Distribution Contract, etc.)		Rate 20 (1) ($000s)	Rate 100 (2) ($000s)	Rate T1 (3) ($000s)	Program Total (4) ($000s)
1							
2							
3							
4							
5							
6			Total	1,308	2,112	1,484	

2011 Actual Unaudited DSM Spending

Line No.	Program Name	Particulars/Details (e.g., Resource Acquisition, Market Transformation, Distribution Contract, etc.)		Rate 20 (1) ($000s)	Rate 100 (2) ($000s)	Rate T1 (3) ($000s)	Program Total (4) ($000s)
7							
8							
9							
10							
11							
12			Total	573	834	4,364	

**Note – Totals as shown in Exhibit A, Tab 1, Schedule 3 are provided*

b) For each of the programs and rates listed in Table 1, Please provide the Total Resource Cost ("TRC") achieved and fill out Table 2 below.

2011 Unaudited TRC

Line No.	Program Name	Particulars/Details (e.g., Resource Acquisition, Market Transformation, Distribution Contract, etc.)	Rate 20 (1) (M$)	Rate 100 (2) (M$)	Rate T1 (3) (M$)	Program Total (4) (M$)
1						
2						
3						
4						
5						
6		Total				

Response:

a)

2011 Forecasted and Actual DSM Spend

Line No.	Program Name	Particulars/Details (e.g., Resource Acquisition, Market Transformation, Distribution Contract, etc.)	Rate 20 (1) M$	Rate 100 (2) M$	Rate T1 (3) M$	Program Total (4) M$
	Forecast		$1.308	$2.112	$1.484	$23.190
	Actual					
1	Residential/Commercial	Resource Acquisition				$13.194
2	Low Income	Resource Acquisition				$2.055
3	Distribution Contract	Distribution Contract	$0.573	$0.834	$4.364	$9.450
4	Market Transformation	Market Transformation				$1.572
5	Total Actual Budget		$0.573	$0.834	$4.364	$26.271

b)

2011 Unaudited Gross TRC

Line No.	Program Name	Particulars/Details (e.g., Resource Acquisition, Market Transformation, Distribution Contract, etc.)	Rate 20 (1) M$	Rate 100 (2) M$	Rate T1 (3) M$	Program Total (4) M$
1	Residential/Commercial	Resource Acquisition				$49.37
2	Low Income	Resource Acquisition				$15.34
3	Distribution Contract	Distribution Contract	$12.27	$29.69	$185.29	$324.38
4	Market Transformation	Market Transformation				
5						
6		Total	$12.27	$29.69	$185.29	$389.09

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Page 11

a) Union mentions, at line 4, that there were no 2011 DSM "volumes" included in 2011 rates. Please clarify what Union means by "DSM volumes" and how they might be included in rates.

b) Union mentions, at lines 4-7, that "the process to finalize DSM balances for 2011 includes an audit of Union's DSM Annual Report, which is subsequently reviewed by the Evaluation and Audit Committee, communicated to the DSM Consultative and filed with the Board". Please provide a copy of Union's audited DSM Annual Report.

Response:

a) Union's description of DSM "volumes" refers to the lost volumes due to Union's DSM programs. For ratemaking purposes in 2011, as shown at EB-2010-0148, Rate Order, Working Papers, Schedule 11, Union's Board-approved 2011 rates include volume adjustments related to audited 2009 DSM volumes associated with 2009 DSM activities.

b) A copy of the audited DSM Annual Report will be forwarded to all Consultative members once the 2011 Audit is complete. Union will file its audited DSM Annual Report by June 30, 2012.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Page 12

Preamble: At lines 7-9, Union states:

"The Board's EB-2006-0021 Decision (Phase 1, page 30) allows Union to spend up to 15% more than what was included in rates provided the "additional funding was spent on incremental program expenses."

Please explain how Union decides to spend this additional 15%, including on which rate classes. Are there any processes or procedures that Union follows when making these decisions? If so, please provide/explain.

Response:

In EB-2006-0021 parties agreed that a Utility may spend and record in the DSMVA for reimbursement to the utility, in any one year, no more than 15% (fifteen percent) of that Utility's DSM budget for that year. The overspend is not rate class specific but based on the overall budget. In 2011 the overall DSMVA, excluding the incremental Low-income budget, was $1.026 million or 4% of the overall 2011 DSM budget of $24.889 million.

Please also refer to the response at Exhibit B1.3.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Page 13, Table 2

Preamble: Table 2 reads as follows:

Table 2
2011 DSM Overspend

Line No.	Particulars ($000's)	2011 Plan	2011 Actual	Variance
1	Residential	3,139	2,699	(440)
2	Low-Income	1,903	1,729	(174)
3	Commercial	5,666	4,143	(1,523)
4	Distribution Contract	4,990	8,737	3,747
5	Market Transformation	1,464	1,572	108
6	Other Direct Program Costs	7,727	7,035	(692)
7	Subtotal	24,889	25,915	1,026
8	Incremental Low-Income	-	2,056	2,056
9	Total	24,889	27,971	3,082

a) Please explain the term "Distribution Contract" and what it is meant to capture.

b) According to Line 4 in Table 2, while Union's planned 2011 DSM spend was $4,990,000, its actual 2011 DSM spend was $8,737,000 (a variance of approx. $3,747,000). Please explain this variance (how it came to be and the rationale behind the spending). Please explain why this exceeds the 15% referred to in IR #3.

c) Explain how the Distribution Contract amount was spent – i.e. on what programs and for the benefit of which rate classes. Please also provide the benefits achieved from this expenditure.

Response:

a) "Distribution Contract" refers to large volume customers in contract rate classes, where custom projects are offered in the industrial, agricultural, commercial and power generation market segments.

b) Please see the responses at Exhibit B1.3 and B2.3.

c) The direct Distribution Contract's 2011 expenditure of $8.737 million included both program and administrative costs. Of the $8.737 million, $8.014 million was paid to Distribution Contract Customers in the form of customer incentives related to DSM projects. The following rate classes benefited from the Distribution Contract Program: Rate 20, Rate 100, M4, M5, M7, and T1.

From the expenditure stated above a gross total resources costs benefit of $324.38 million was achieved.

Please see the response at Exhibit B 1.2 Attachment 1 for a list of projects and benefits.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Page 16

Preamble: At lines 5-9, Union states:

"In accordance with previous Board-approved practice, Union is proposing to dispose of the recorded SSM balance related to unaudited 2011 DSM activities. Recognizing this balance may still change following the audit, any amount disposed of would be subject to a future true-up. Any true-up amount will be captured in the deferral account for future disposition."

Please explain the rationale behind Union's decision to dispose of the recorded SSM balance related to unaudited 2011 DSM Activities (as opposed to deferring these amounts). If Union is basing this decision on "Board-approved practice", please provide references or examples to support the decision. Please also identify when the audited report will be available.

Response:

The rationale behind Union's decision to dispose of recorded SSM balances related to unaudited 2011 DSM activities is based on Board-approved practice. The common practice is to dispose of unaudited DSM-related amounts in Union's earnings sharing and deferral account disposition proceedings and then to true-up those amounts in the year immediately following based on the actual audited DSM results. This methodology was approved by the Board in EB-2009-0052, EB-2010-0039 and most recently EB-2011-0038.

The Board reaffirmed this practice continues to be appropriate in its Decision and Order for Union's 2010 deferral account disposition (EB-2011-0038). The Board states on page 33 and 34 of its Decision and Order:

"The Board finds that the 2011 earnings sharing and deferral account disposition proceeding is the appropriate time to review the audited DSM results and parties can take any position on the audited results at that time.

The Board finds that the same process should be followed this year and therefore, it is appropriate to dispose of the unaudited DSM-related balances in this proceeding (which Ontario Energy Board will be subject to true-up in Union's 2011 earnings sharing and deferral account disposition proceeding) without any adjustments."

Union will file the final audited 2011 Annual Report with the Board on June 30th, 2012.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Page 16

Preamble: At Lines 11-12 on Page 16 and Lines 4-10 on Page 17, Union states:

"In addition to the balance in the SSM deferral account Union is claiming a $0.544 million incentive for the 2011 incremental Low-income program…Union is proposing to dispose of the forecast Low-income balance related to unaudited 2011 Low income activities as measured by the Home Weatherization Scorecard at this time. The variances between the payout balances calculated out of audited and unaudited results would be subject to a future true-up. Any true-up amount will be captured in a future disposition in the same way the LRAM variance from 2011 has been trued up in this proceeding."

Please explain the rationale behind Union's decision to dispose of the forecast Low-income balance related to unaudited 2011 Low income activities as measured by the Home Weatherization Scorecard at this time.

Response:

Please see the response at Exhibit B2.5.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Page 19, Table 4

Preamble: Table 4 reads as follows:

Table 4
IFRS Conversion Costs by Year

Line No.	Particulars ($ Millions)	2008 (a)	2009 (b)	2010 (c)	2011 (d)	2012 (e)	2013 (f)	2014 (g)	Total (h)
1	Proposed by Union	1.918	2.071						3.989
2	Less capital expenditures	0.953	0.459						1.412
3	O&M	0.965	1.612						2.577
4	Revenue requirement	-	-	0.124	0.335	0.538	0.505	0.244	1.747
5		0.965	1.612	0.124	0.335	0.538	0.505	0.244	4.324

In light of the fact that there are no expenditures listed in Table 4 for the years 2010-2014, please provide calculations for and explain the revenue requirement numbers for these years.

Response:

The IFRS conversion costs provided in Table 4 were agreed to as part of the EB-2010-0039 Settlement Agreement and approved by the Board on August 10, 2010.

IFRS Revenue Requirement

Particulars ($ millions)	2010	2011	2012	2013	2014
Depreciation	0.176	0.353	0.353	0.353	0.177
Interest	0.064	0.052	0.034	0.017	0.004
Return	0.041	0.032	0.022	0.011	0.003
Current tax	(0.157)	(0.102)	0.129	0.124	0.061
Revenue requirement	0.124	0.335	0.538	0.505	0.245

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Pages 23-24

Preamble: Union's application (at Line 15, Page 23 – Line 8, Page 24) reads as follows:

"The revenue requirement impact is a credit of $0.390 million, of which 50% or $0.195 million is the ratepayer portion. In 2010 Union had a tax savings of $3.330 million related to capital additions, including $0.032 million of O&M overhead capitalization. The revenue requirement impact for the 2010 Capital additions in 2011 is a credit of $0.406 million, of which 50% or $0.203 million is the ratepayer portion. The combined revenue requirement impact for 2011 is $0.796 million, of which 50% or $0.398 is the ratepayer portion. The calculation of this balance is provided in Table 6 below. The HST impact on capital expenditures will be included in rate base when Union resets its rates in 2013."

Table 6 (see page 24) reads as follows:

Table 6
HST Capital Summary

Line No.	Particulars ($ Millions)		2011	2010	Total
	Capital Additions				
1	Capital PST Savings Estimate		6.395	3.330	9.725
2	1/2 year rule		0.5	N/A	
			3.198	3.330	6.528
3	Depreciation	3.30%	0.106	0.110	0.216
4	Interest	4.61%	0.147	0.154	0.301
5	Return	3.07%	0.098	0.102	0.200
6	Income Taxes	28.25%	0.039	0.040	0.079
7	Revenue Requirement Impact		0.390	0.406	0.796

Union explains that the HST impact on capital expenditures will be included in rate base when Union resets its rates in 2013. Please explain the rationale behind this decision – i.e. why is the "ratepayer portion" of the credit not being refunded immediately?

Response:

The revenue requirement associated with capital expenditures is recovered through rates. Consistent with this approach, the ratepayer portion of the credit for capital expenditures is also calculated and refunded to the ratepayer based on the revenue requirement until 2013.

When Union rebases rates in 2013, the capital savings from HST will be included as a reduction to rate base, thereby reducing the annual revenue requirement.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Schedule 2, Page 3

Preamble: This table provides 2011 Unaudited LRAM particulars.

Column (a) in the table provides "2011 Unaudited Volumes". Please provide the final approved/audited volumes for the Rate 20, Rate 100 and T1rate classes.

Response:

Please see the response at B1.2 a).

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 1, Schedule 3

a) Line No. 6 of this table provides DSM numbers for the T1 rate class. While the DSM costs in 2011 rates for T1 is listed at $1,484, 000, the actual 2011 DSM costs for T1 were $4,364,000 (see column (b)). This results in an account balance of $2,880,000 (see column (c)). Please address this difference by providing the following information:

   i. Explain how the $4,364,000 was spent (i.e. on which programs);
   ii. Explain the rationale behind such significant overspending for the T1 rate class; and
   iii. Please discuss any benefits that T1 achieved because of this overspend.

b) The "Notes" section at the bottom of this table (detailing DSMVA) is blank. Please provide.

Response:

a) The $4.3 million was spent to deliver and provide incentives for custom programs. This included 229 of projects for the T1 rate class, an increase of 137 projects over 2010 results. The greatest opportunity to influence DSM savings in 2011 was identified in the Distribution Contract market, primarily in the T1 Rate class and the budget was allocated accordingly. The results of the increase in spending increased m^3 savings generated by T1 rate class from 32,818 10^3m^3 in 2010 to 86,670 10^3m^3 in 2011, an increase of over 160%. In addition, $185 million in TRC or 47% of the total TRC was generated by the T1 Rate Class in 2011.

b) Please see Attachment 1.

Filed: 2012-06-08
EB-2012-0087
Exhibit B2.10
Attachment 1

UNION GAS LIMITED
Demand Side Management Variance Account

Line No.	Particulars ($000's)	2011 DSM Costs in 2011 Rates[1]	2011 Actual DSM Costs [2]	2011 Account Balance
		(a)	(b)	(c) = (b) - (a)
	South			
1	M1	7,612	10,106	2,494
2	M2	3,154	3,300	146
3	M4	2,391	987	(1,403)
4	M5	-	2,104	2,104
5	M7	909	588	(320)
6	T1	1,484	4,364	2,880
7		15,549	21,450	5,900
	North			
8	Rate 01	2,269	2,568	299
9	Rate 10	1,951	846	(1,106)
10	Rate 20	1,308	573	(735)
11	Rate 100	2,112	834	(1,278)
12		7,640	4,821	(2,819)
13	Total	23,190	26,271	3,081

Notes:

(1) The allocation of the costs is consistent with EB-2005-0520, Exhibit G3, Tab 5, Schedule 21, updated to reflect EB-2005-0520 Board decision.

(2) Includes $2.056 million related to incremental Low-income DSM activities per EB-2010-0055. $1.756 million has been allocated to M1 and $0.300 million has been allocated to Rate 01.

UNION GAS LIMITED

Answer to Interrogatory from
Association of Power Producers of Ontario ("APPrO")

Reference: Exhibit A, Tab 2, Page 3

Preamble: Under "2011 Earnings Sharing", Union provides the following at lines 2-5:

"The benchmark return on equity ("ROE") for 2011 was 8.10%. Union's actual ROE from utility operations in 2011 was 11.57% or 347 basis points above the 2011 benchmark ROE. This results in earnings sharing for 2011 of $16.652 million (Tab 2, Appendix B, Schedule 1, column (d), line 35)."

Please provide what amount of the $16.652 million would be delegated to T1, Rate 20, Rate 100 and Rate 25 customers – both to each rate class as a whole and to the average customer within that rate class.

Response:

The allocation of proposed 2011 Earnings Sharing amounts to Rate 20, Rate 25, Rate 100 and Rate T1, as shown at Exhibit A, Tab 3, Schedule 1, page 2, column (b), is provided in Table 1.

Table 1

2011 Proposed Earnings Sharing Amounts
for Rate 20, Rate 25, Rate 100 and Rate T1

Rate Class	2011 Proposed Earnings Sharing Amount ($000's)
Rate 20	(274)
Rate 25	(123)
Rate 100	(362)
Rate T1	(824)

For an average Rate 20 customer with an annual volume of 10,500,000 m^3, the proposed 2011 Earnings Sharing credit will be approximately $4,543.

For an average Rate 25 customer with an annual volume of 1,400,000 m^3, the proposed 2011 Earnings Sharing credit will be approximately $1,094.

For an average Rate 100 customer with an annual volume of 110,000,000 m^3, the proposed 2011 Earnings Sharing credit will be approximately $21,044.

For an average Rate T1 customer with an annual volume of 80,000,000 m^3, the proposed 2011 Earnings Sharing credit will be approximately $14,511.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Page 3

Preamble: The evidence stated that Union's approved 2011 rates included UDC of 4.4 PJ in Union North and 0.2 PJ in Union South. Actual 2011 UDC was 2.0 PJ in Union North, and no PJ in Union South. In 2011, Union North collected $6,217,000.00 in rates and Union South collected $147,000.00 in rates, but incurred UDC of only $525,000.00 in Union North and $0.00 in Union South.

a) Please explain why the increased UDC in Union North was only fifty percent of forecast UDC.

b) Please explain the difference, a factor of 12X, between the amount collected in rates in Union North relative to the UDC incurred, both in absolute terms, and relative to the difference in gas volumes forecast versus incurred, only a factor of 2X.

c) Please explain the variance between UDC forecast and incurred in Union South.

Response:

a) Union's actual UDC volumes in 2011 were 2.0 PJ. Actual UDC volumes were lower than forecast due to colder than normal weather for the 2010/2011 winter, and increased volume due to more customers returning to system gas, offset in part by unaccounted for gas gains.

b) Unfilled capacity was sold on the secondary market to minimize UDC. Revenues generated from the transportation releases were credited to the UDC deferral account mitigating the UDC that was forecasted in rates.

c) Please see the response to a) above.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Page 13

Account No. 179-112 Gas Distribution Access Rule (GDAR) Costs.

a) Please provide a copy of Union's Customer Service Policy referred to at page 14.

b) Did Union apply for a Z-factor treatment for these costs in its 2012 rates application? If not, why not?

c) When did Union begin work on the policy? Please provide any contracts or other written communications between Union and the External Customer Service Provider on the subject.

Response:

a) Please see Attachment 1.

b) Union did not apply for z-factor treatment for these costs. The Board issued a Notice of Amendment to a Rule: Residential Customer Service Amendments to the Gas Distribution Access Rule ("GDAR") on October 14, 2011 (EB-2010-0280) requiring natural gas utilities to make certain changes to and comply with a Customer Service Policy. In order to comply with the amendments to GDAR Union was required to make process and system changes and these costs are recoverable through the GDAR deferral account similar to the implementation of GDAR in RP-2000-0001.

c) Union began working on the Policy and the modifications to service offerings requested by the OEB, in August 2011.

The contracts between Union and third parties are subject to confidentiality agreements. Accordingly, Union has filed the contracts and related project specific documents under the Board's Practice Direction on Confidential Filings under separate confidential cover.

Union Gas

CONDITIONS OF SERVICE

Foreword

Union Gas is a distributor of natural gas in the province of Ontario. We are committed to serving our customers in a safe, reliable and efficient manner. This document has been prepared to explain, in a summary form, the conditions which govern our operations. It is intended that this communication will help us to better serve our customers.

Except as otherwise noted, the following conditions apply to all gas rates and gas service, by or with Union Gas (referred to as “us” or “we” throughout this document).

We reserve the right to modify, alter or amend these conditions and to make further and other conditions as experience may suggest and as we may deem necessary or convenient in the conduct of our business. These conditions do not supersede any terms and conditions agreed to in our contracts for gas supply with you.

Basic Terminology

British Thermal Unit (BTU)	The amount of heat required to raise the temperature of one pound of water 1 degree Fahrenheit at 60 degrees Fahrenheit.
Company	Union Gas – also referred to as “We” and “Us” throughout this document. Refers to Union Gas, and where appropriate, any member that provides you with Union Gas services or products.
Cubic Metre	One standard cubic metre of gas is the volume of the gas that occupies one cubic metre at a temperature of 15 degrees Celsius and an absolute pressure of 101.325 kPa. (One standard cubic metre equals 35.494 standard cubic feet).
Curtailment	An unplanned suspension of gas delivery caused by a physical failure or a high risk failure on our pipeline system, or non-delivery of gas into our pipeline system.
Customer	An individual, group of individuals, company or corporation responsible for the receipt and payment of goods and/or services provided by the Company. Referred to as “you” and “your” throughout this document.
Customer Service	Work done for you by our service personnel or authorized agents on behalf of us, including the installation and adjustment to meters and regulators and the associated appliance inspections.
Degree Days	A measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below the reference temperature of 18 degrees Celsius. A heating degree day is the difference between 18 degrees Celsius and the average temperature of the day. For example if the average given temperature on any given day is 10 degrees Celsius, then the number of degree days would be 8 (18-10). If the average temperature for the day is 18 degrees Celsius or higher, then the number of degree days for that day would be zero. As the weather gets colder the number of degree days increases. Union Gas uses degree days as a measure of coldness for comparative purposes. Generally the higher the degree days recorded, the higher the gas used on an account.
Gas	Natural gas or manufactured gas or liquefied petroleum gas or any mixture of these containing not less than 36 megajoules per cubic metre.
Gas Appliance	A device that consumes or is intended to consume a gas

	and is certified or field approved as acceptable to the provincial authority having jurisdiction.
Gas Sales Contract	A contract between the Company and a customer prescribing rates and conditions for the supply of gas, transportation and storage services to the customer.
Main	The pipe that is used to carry natural gas to a service.
Main Extension	The addition of pipe to an existing main to serve new customers.
Point of Delivery	The point(s) or points at the outlet side of our meter(s) at the location(s) where the gas is delivered to you.
Property Line	The Line that separates the boundary between one property and the next immediately adjacent property whether it is public or private.
Rate Schedule	One of a set of schedules filed with and approved by the Ontario Energy Board describing a category of customer, the rates charged for gas supplied to customers in the category and the particular terms under which gas is supplied to such customers. The rates determined by Union Gas and approved by the Ontario Energy Board that outlines the type of customer and the payment schedules for each of these customer types.
Service Lateral	Piping that conveys gas from a main to your meter.
Service	*Residential:* Customers supplied for residential purposes in a single family dwelling or building, or in an individual flat or apartment within a multiple family dwelling or building or a portion of a building occupied as the home, residence, or sleeping place of one or more persons. ▪ When service for residential purposes is supplied to two or more families served as a single customer under one rate classification contract that service is considered as commercial but is counted as only one customer. ▪ Residential premises also used regularly for professional or business purposes (such as doctor's office in a home or where a small store is integral with the living space), are considered as residential where the residential use of gas is half or more than half of the total service. *Commercial:* Applies to customers engaged in selling, warehousing or distributing a commodity, in some business activity or in some other form of economic or social activity (also includes professions). ▪ The size of the customer's operation or volume of use is not a criterion for determining Commercial service. *Industrial:* Customers engaged in a process which creates or changes raw or unfinished materials into another form or product, or who change or complete a semi-finished

material into a finished form.

- All gas used on premises which qualify under the industrial classification is to be classified as industrial service.
- The size of the customer's operation or volume of use is not a criterion for determining Industrial Service.

1. About our Area and Gas Services

1.1 Area Served by Company

As outlined in these conditions of service, Union Gas has an adequate supply of gas to serve its customers, and has properly installed pipe and piping according to the appropriate legislative requirements. Union Gas supplies gas to over 400 communities within the 230 municipalities where Union Gas holds a franchise agreement. These are considered traditional place names and may not in all cases reflect the current names of these communities.

Communities

Aberfoyle
Acton
Adelaide Twp
Ailsa Craig
Alberton
Aldborough Twp
Alma
Alvinston
Amabel Twp
Amherstburg
Amherstview
Ancaster
Appin
Arkona
Arran Twp
Artemesia Twp
Arthur
Arthur Twp
Astra
Atherley
Atikokan
Atwood
Awrey Twp
Ayr
Azilda
Baden
Baltimore
Barwick
Batawa
Bath
Bayfield
Bayham Twp
Beachville
Beardmore
Belleville
Bentinck Twp
Berwick
Bewdley
Blandford-Blen Twp
Banshard Twp
Blenheim
Blezard Valley
Blind River
Bloomfield
Bloomingdale
Blue Mountains
Blyth
Bosanquet Twp
Bothwell
Bracebridge
Branchton
Brant Twp
Brantford
Brantford Twp
Breslau
Brigden
Brighton
Brights Grove
Brockville
Brooke Twp
Brookville
Bruce Mines
Brussels
Burford
Burford Twp
Burgessville
Burks Falls
Burlington
Cache Bay
Caledonia
Callander
Calstock
Cambridge
Camden Twp
Camlachie
Campbellville
Canboro
Canborough Twp
Canfield
Cannifton
Capreol
Caradoc Twp
Cardinal
Carlisle
Carrick Twp
Castleton
Cathcart
Cayuga
Cayuga N Twp
Cayuga S Twp
Cedar Springs
Centralia
Centreton
Chaput Hughes
Charing Cross
Charlotteville Twp

Chatham
Chatham Twp
Chatsworth
Chelmsford
Chesterville
Clifford
Clinton
Cobalt
Cobourg
Cochrane
Colborne
Colborne Twp
Colchester N Twp
Colchester S Twp
Collingwood Twp
Conestogo
Coniston
Copetown
Copper Cliff
Corbyville
Cornwall
Corunna
Courtland
Courtright
Crediton
Crysler
Culross Twp
Cumberland Beach
Dashwood
Dawn Twp
Delaware Twp
Delhi
Derby Twp
Dereham Twp
Desbarats
Deseronto
Devlin
Dorchester
Dorchster N Twp
Dorion
Dover Centre
Dover Twp
Dowling
Downie Twp
Drayton
Dresden
Dryden
Duart
Dumfries N Twp
Dumfries S Twp
Dundas
DunnTwp
Dunnville
Dunwich Twp
Durham
Dutton
Ear Falls
Earlton
East Wawanosh Twp
Easthope N Twp
Easthope S Twp
Echo Bay
Eden
Egmondville
Egremont Twp
Ekfrid Twp
Elginburg
Ellice Twp
Elliot Lake
Elma Twp
Elmira
Elora
Emo
Englehart
Enniskillen Twp
Eramosa Twp
Erie Beach
Erieau
Espanola
Essex
Euphemia Twp
Exeter
Falconbridge
Fauquier
Fergus
Finch
Fisherville
Flamborough
Flamborough W Twp
Flesherton
Floradale
Florence
Forest
Fort Frances
Foxboro
Frankford
Freelton
Fullarton Twp
Gananoque
Garafraxa W Twp
Garden River
Garson
Georgetown
Geraldton
Glanbrook Twp
Glen Williams
Glencoe
Glenelg Twp
Goderich
Goderich Twp
Gosfield S Twp
Gowanstown
Grafton
Grand Bend
Gravenhurst
Greensville
Grey Twp
Guelph
Guelph Twp
Hagersville
Haileybury
Hallebourg
Halton Hills
Hamilton
Hanmer
Hanover
Harrisburg
Harriston
Harrow
Harty
Harwich Twp
Hawkesville
Hay Twp
Hearst
Heidelberg
Hensall
Hepworth
Hibbert Twp

Highgate
Hillier
Holland Twp
Holtyre
Hornell Heights
Howard Twp
Howick Twp
Hullett Twp
Huntsville
Hurkett
Huron Park
Ignace
Ingersoll
Ingleside
Inkerman
Innerkip
Inwood
Iron Bridge
Iroquois
Iroquois Falls
Jarvis
Jerseyville
Joyceville
Kakabeka Falls
Kapuskasing
Keewatin
Kenora
Kent Bridge
Keppel Twp
Kilbride
Kilsyth
Kilworth
Kilworth Heights
Kingston
Kingsville
Kirkland Lake
Kitchener
Komoka
La Salette
Lakeport
Lakeshore
Langton
Lasalle
Leamington
Levack
Linwood
Listowel
Lively
Lobo Twp
Logan Twp
Londesborough
London
London Twp
Long Sault
Longford Mills
Longlac
Lowbanks
Lowville
Lucan
Lynden
Lynedoch
Madoc
Maitland
Mannheim
Markdale
Markstay
Marmora
Maryborough Twp
Maryhill
Matheson
Mattawa
Mattice
Maynard
McGillivray Twp
McKillop Twp
Meaford
Merlin
Metcalfe Twp
Middleport
Middleton Twp
Mildmay
Millgrove
Milton
Minto Twp
Mitchell
Mitchell’s Bay
Monteith
Moonbeam
Moore Twp
Mooretown
Morewood
Morpeth
Morris Twp
Morrisburg
Morriston
Mosa Twp
Moulton Twp
Mount Brydges
Mount Elgin
Mount Forest
Mount Hope
Mount Pleasant
Murillo
Nairn Centre
Nanticoke
Napanee
Naughton
Neebing
New Dundee
New Hamburg
New Liskeard
Newburgh
Newbury
Nichol Twp
Nipigon
Nissouri W Twp
Norfolk Twp
Normanby Twp
North Bay
North Buxton
North Cobalt
Norval
Norwich
Norwich N Twp
Norwich S Twp
Norwich Twp
Novar
Oakland
Oakland Twp
Oakville
Odessa
Oil City
Oil Springs
Oliver Paipoonge
Onaping
Oneida Twp
Onondaga Twp
Opasatika

Orford Twp
Orillia
Orkney
Orland
Orrville
Otterville
Owen Sound
Oxford Southwest Twp
Paincourt
Palmerston
Paris
Parkhill
Parry Sound
Peacock Point
Peel Twp
Petersburg
Petrolia
Picton
Pilkington Twp
Pinewood
Plainfield
Plattsville
Plympton Twp
Point Edward
Porcupine
Porquis Junction
Port Dover
Port Elgin
Port Hope
Port Lambton
Port Rowan
Port Ryerse
Port Stanley
Port Sydney
Powassan
Prescott
Princeton
Puslinch Twp
Quinte West
Rainham Twp
Rainy River
Raleigh Twp
Rama
Ramore
Red Rock
Ridgetown
Rockwood
Rodney
Romney Twp
Rondeau Park
Roseville
Rothsay
Rutherglen
Salem
Sarawak Twp
Sarnia
Sauble Beach
Saugeen Twp
Sault Ste. Marie
Schumacher
Scotland
Seaforth
Sebringville
Selby
Selkirk
Seneca Twp
Shallow Lake
Shanty Bay
Sherbrooke Twp
Shrewsbury
Shuniah Twp
South Mountain
South Porcupine
South River
Southampton
Southwold Twp
Springford
St Agatha
St Andrews West
St Clements
St George
St Jacobs
St Marys
St Thomas
St Vincent Twp
St Williams
Stanley Twp
Stephen Twp
Stirling
Stockdale
Stoney Creek
Stratford
Strathroy
Stratton
Sturgeon Falls
Sudbury
Sullivan Twp
Sundridge
Swastika
Sydenham Twp
Tara
Tavistock
Tecumseh
Teeswater
Teeterville
Temagami
Thamesford
Thamesville
Thedford
Thessalon
Thornbury
Thorne
Thunder Bay
Tilbury
Tilbury E Twp
Tillsonburg
Timmins
Townsend
Townsend Twp
Trenton
Trout Creek
Tuckersmith Twp
Tupperville
Turnberry Twp
Tweed
Usborne Twp
Val Caron
Val Gagne
Val Rita
Val Therese
Vanastra
Vermilion Bay
Verner
Vickers Heights
Vittoria
Wahnapitae
Walkerton
Wallace Twp

Wallaceburg
Wallenstein
Walpole Twp
Walsingham
Walsingham N Twp
Walsingham S Twp
Wardsville
Warren
Warwick Twp
Waterdown
Waterford
Waterloo
Watford
Wellesley
Wellesley Twp
Wellington
West Lorne
West Montrose
Westbrook
Westlake
Westminster Town
Wheatley
Whitefish
Wiarton
Wilkesport
Williams E Twp
Williams W Twp
Williamsburg
Wilmot Twp
Winchester
Windham Twp
Windsor
Wingham
Winterborne
Woodhouse Twp
Woodlawn
Woodslee
Woodstock
Wooler
Woolwich Twp
Wyoming
Yarmouth Twp
York
Zone Twp
Zorra Twp
Zorra-Tavistock East
Zurich

1.2 Quality of Gas

The gas to be delivered shall be natural gas or its equivalent from our present or future sources of supply, and shall:

- Have a heating value of a minimum 36 megajoules per cubic metre
- Be commercially free from objectionable matter

NOTE: *The gas delivered to customers attached to field gathering lines may vary from pipeline quality gas due to local well conditions.*

1.3 Gas Distribution Services

Gas distribution services will be made available to all residential, commercial and industrial customers in all communities served by us:

- when we have determined transportation, distribution and/or storage capacity is available, and
- when we determine that the installation of gas piping (and related gas equipment) to serve you is economically feasible

Applying for more than one type of rate schedule

Customers may have gas distribution services under more than one rate schedule, as follows:

- Provided the customer meets all of the requirements for applicability, which are found in each rate schedule.
- This service may be taken through one meter, provided:
    - there is agreement upon a definite volume of gas that you will purchase under each rate
    - the volume of gas that falls under distribution charges, and
    - the delivery sequence

Gas Distribution Interruptions

Curtailment, or requests to stop gas use, may be required if the supply of gas is jeopardized, in the following situations:

- If there is an actual or threatened shortage of natural gas beyond our control
- When required because of curtailment or restrictions ordered by an authorized government authority

We assume no liability for any loss of production or for any damage whatsoever due to curtailment or discontinuance or because of the length of advance notice given that directs that curtailment or discontinuance.

1.4 Limitations of Liability

We shall use care and diligence to furnish sufficient gas distribution capacity but we assume no liability for damages or loss resulting from any failure of supply.

It is the customer’s responsibility to provide and maintain:

- All pipes and valves to take the gas from the meter
- All equipment used in the burning of gas
- All vents necessary to efficiently take all products of combustion (including unburned gas if any) to the outside air

2. Initiation of Service

2.1 Main Extensions

We will extend our gas main within our franchise area to serve new customers (or potential customers) when:

- those requirements will not disturb or impair the service to prior users
- we determine the extension of the gas main is economically feasible

When we determine the extension of our facilities is not economically feasible, the applicant will be required to pay a contribution in aid of construction. We will determine the contribution amount before the extension of such facilities.

2.2 Service Lateral Installations

Service laterals will be installed provided that:

- There is an application for gas.
- The site of the service lateral installation is within our franchise area.
- Adequate distribution facilities are available.
- Any necessary main extension can be justified in accordance with our line extension practice.
- The requested hourly volume is available in accordance with the required supply pressure.
- In our sole discretion, we have an adequate gas supply to provide gas service.

We will designate the location of the service lines, meters and regulators, and will determine the amount of space that must be left unobstructed for the installation.

We do not assume ownership, responsibility or maintenance of piping beyond the outlet side of the meter or regulator set up.

If a customer wants us to install main on property that is not owned by the customer, such as road allowance, municipal or neighbouring property, land rights (in the form of easement) will be required for the installation / maintenance of gas lines (and equipment) from that property owner.

We shall try to restore property to the approximate condition in which it was found before starting our operations. This includes property that is excavated or may be disrupted during laying, constructing, repairing or removing our facilities.

2.3 Customer Costs

Gas service laterals extending from the property line to the meter location will be installed according to our policies and procedures. Customers are charged for these services as follows:

Residential Customers

- Billed for any excess charges beyond 30 metres

- Billed for aid as calculated using the Company's test of economic feasibility for service lateral extensions
- Billed for charges related to the installation of the meter set beyond our approved location.

Commercial and Industrial Customers

- Union Gas uses a Distribution Related Economic Analysis Model to cost Commercial and Industrial services. If the service does not meet an economic feasibility benchmark, a customer will be expected to pay aid to construction costs in order to meet our internal economic feasibility benchmark.
- If aid to construction is required, Union Gas will provide the costs to the customer, for approval prior to initiating the installation of the service

When the installation is effected by us, our cost is:

- Material used at inventory value (including appropriate stores expense).
- Cost of direct labour on installation (including appropriate payroll burden).
- Cost of transportation and mobile work equipment.
- Cost of contract work.

2.4 Relocation of Service Laterals

For service lateral relocations requests, the cost will be based on size and nature of any added gas that is required. Requested relocations for convenience or aesthetics will normally be on a charge basis.

We reserve the right to make changes, extensions, or replacements of service lines.

2.5 Customer Piping

As an applicant for service, a customer shall at their expense, equip premises with all piping and attachments from the meter to the appliances or equipment served. It is the customer's responsibility to maintain the piping and equipment beyond the outlet side of the meter. Such piping and attachments shall be installed and maintained in accordance with the Ontario Regulation 212/01 – Gaseous Fuels, as amended.

If we know that the piping and/or appliances or heating equipment are defective, or not in accordance with applicable rules and regulations, ordinances or codes, we will not connect a meter.

We may discontinue gas service at any time that we find defective or unsafe conditions on:

- the piping
- the venting
- the appliances or other gas-fired equipment

Notification and Maintenance

If there is leakage or escape of gas on a customer's premises, the customer is required to immediately notify Union Gas. The emergency number for Union Gas Limited is 1-877-969-0999.

Customers should ensure that their chimney or gas equipment venting system is clean and clear of obstructions.

If injury or damage occurs because of the escape of gas or products of combustion of gas from building piping, venting systems, or appliances on the customer's side of the Point of Delivery, we are not liable, unless the injury or damage can be traced to our negligence.

2.6 Meters and Meter Location

A meter or meters of standard manufacture, that we install (unless otherwise specified) shall measure the gas supplied. We will furnish each customer with a meter of a size and type that will adequately serve the customer's requirements. These meters are our property. We can inspect, remove or replace these as we deem necessary or in accordance with applicable rules, regulations, ordinances or codes.

Non-contiguous customer premises shall be metered and billed separately. Premises are considered non-contiguous when they:

- are not on the same tract of land
- are complete and not integrated with or part of other premises
- are integrated with or part of other premises

Tracts of land separated by public streets, roads, lanes or alleys shall be considered non-contiguous lands.

Residential, Commercial, Industrial meters will be located near a building, taking into consideration the following:

- safety
- distribution facilities
- customer equipment
- noise
- structural design
- landscaping
- accessibility for meter reading and servicing

Inside locations require the approval of the District Manager or designate.

Anyone who is not an authorized agent of the Company shall not be permitted to connect or disconnect our meters, regulators or gauges, or in any way alter or interfere with our meters, regulators or gauges.

Customers are responsible for protecting all metering and regulating equipment necessary for the supply of gas and for keeping it accessible at all times. Customers will be held liable for any such loss or damage beyond ordinary wear and tear, and if required, shall pay us the cost of necessary repairs or replacements.

We are not responsible for damages caused by the freezing of water pipes, water heaters and hot water systems in your premises unless the damage can be traced to our negligence.

2.7 Delivery and Use of Gas

Our gas delivery and the customer's use of gas constitute a contract subject to these provisions, even if a contract has not been signed.

The place of delivery of all gas purchased under sales service, or redelivery in the case of direct purchase, shall be at the outlet of our meter located at or near the point or points of connection with the customer's facilities. At that point all gas delivered shall become the customer's property.

All gas passing through the meter, whether it is used or lost through leaks in pipes, apparatus, or otherwise is the customer's responsibility and the customer shall pay for that gas.

Gas sold to non-contract customers at excess pressure shall be sold by the cubic metre corrected to a base temperature and pressure.

2.8 Inspection of New Installations

All inspections shall conform to the Technical Standards and Safety Act and regulations made under the Act.

An inspection will be made of new installations of supply piping and gas appliances and installations in accordance with Company practice as follows:

- where premises are connected to a supply of gas for the first time.
- in accordance with the requirements of the Technical Standards and Safety Act and the regulations made under the Act.

If the inspection reveals that repairs or major adjustments are required, the customer will be advised.

3. Maintenance of Service

3.1 Customer Service Policy Statement

Union Gas provides customers with specific and specialized service. The following services are provided free of charge:

- Emergency response
- Inspections mandated by applicable legislation
- Minor adjustment service to natural gas equipment (i.e. work that can be completed within 30 minutes and does not require any appliance parts, special tools or special equipment). Customers requiring additional appliance service will be advised to contact a third party service provider.

3.2 Access to Premises

Our authorized representatives shall have access to a customer's premises at all reasonable times and upon reasonable notice to inspect, read, test, repair, or replace the meter or meters, appliances and equipment used in connection with gas service.

3.3 Testing Meters

We will test meters when necessary, or:

- upon a customer's request
- when required to ensure accordance with legislative requirements.

If there is an unresolved dispute between two parties over meter accuracy, the test process must be initiated through Measurement Canada. This maintains the independence of the dispute process and requires the disputing party, normally the customer, to contact Measurement Canada directly.

Measurement Canada sets out Federal Regulations Union Gas must follow with regard to Gas Measurement. Union Gas is a fully accredited Gas Utility with authorization from the Federal Government to test and seal meters.

If a customer requests a meter accuracy check, and it meets the regulated accuracy requirements during the inspection, we may charge any additional cost for the meter removal and test. This is in addition to the Government inspection fee.

3.4 Resale Prohibited

Gas shall not be resold or redistributed (pursuant to the definitions of those terms in the OEB Act) directly or indirectly by the customer, except:

- gas purchased under the Company's Rate Schedule M1, M2, Rate 01 and Rate 10 for resale as motor vehicle fuel gas (as that term is defined in Ontario Regulation 805/82), or
- gas purchased under the Company's Rate Schedules M9 and M10 and Rate 77 by a customer, that is itself a distributor of natural gas.

4. Customer Care

Section 4 applies to any customer that has not entered into a Gas Sales Contract with Union Gas. For customers that have entered into a Gas Sales Contract with Union Gas, the terms and conditions set out in that contract will supersede the information contained within this section.

4.1 Establishing an Account

Whether a new customer or moving from an existing Union Gas account, customers should notify Union Gas before taking possession of a new home. Account requests can be submitted online or by phone at 1-888-774-3111. Accounts are subject to a one-time activation fee. Customers with Union Gas may be required to provide a security deposit. See section 4.11 for details.

Once delivery of gas to a premise has been established, a contract between the customer and Union Gas is in effect until delivery of gas is discontinued. The customer agrees to pay for services provided, and is liable for all gas supplied to the premises and for the safe custody of Union Gas property.

4.2 Meter Reading

Union Gas makes every effort to read all meters on a monthly schedule. Sometimes we estimate bills if inaccessibility or weather prevents us from reading the meter within a few days of the normal date.

Customers may elect to supply their own meter reading either online or by telephone at 1-888-774-3111. When submitted on a timely basis, these readings will be used in the monthly bill calculation.

If usage is estimated, any necessary adjustments will be included in the next actual meter reading.

On rare occasions, we may have to estimate a bill if the metering equipment malfunctions or has been damaged.

Commercial / industrial non-contract excess pressure customers' meters may be read daily or weekly.

4.3 Billings for Accounts

Consolidated Billing

Customers may combine several meters on to one gas bill if the meters are located on contiguous tracts of land not divided by a public right-of-way. In such cases, an additional service charge as specified in the current rate order shall be rendered each month for each of these meters.

Master Summary Billing

Master Summary Billing summarizes the invoices associated with multiple accounts on one Master Account. Customers choosing this option receive no more than four Master bills per month, depending on the number and location of meters included in their various individual accounts.

4.4 Bill issuance and Payment

Bills are issued on a monthly basis. Invoices are due when rendered and customers are provided a period of 20 days for payment before a Late Payment Charge is applied to their account. Both the invoice issue date and the Late Payment applicable date are printed on all invoices. Whether the customer is issued a paper or electronic invoice, the dates and timelines are the same.

Gas Charges are calculated using rates approved by the Ontario Energy Board.

Each monthly gas invoice will include a set 'monthly charge' that is a set amount charged to every customer regardless of the amount of gas used. It partially covers the cost of maintaining a safe gas distribution system 24 hours a day, every day. The monthly charge will be prorated on initial, final and seasonal invoices when the period covered by the bill is less than 25 days. The amount of the monthly charge is part of the approved Ontario Energy Board rate structure.

Invoices are due when rendered. Union Gas' billing and payment options include:

- **Automatic payment plan:**
  Automatically withdraw payment from your bank account.

- **Paperless billing:**
  Use Union Gas' free paperless billing option to receive your bill online.

- **Equal Billing Plan:**
  Enjoy the benefits of predictable monthly billings all year.

- **Combine Billing and Payment Options:**
  Bundle Paperless Billing, Equal Billing Plan and the Automatic Payment Plan to make monthly payments even more convenient.

Join our billing and payment options online or by telephoning 1-888-774-3111.

More payment options:
- Online banking through your financial institution
- Telephone banking
- Automatic Teller machine
- In person at most banks and financial institutions
- Pay your bill using your credit card online or through our automated telephone service at 1-888-774-3111. Please note that this credit card service is powered by Paymentus Corporation and is subject to a service fee of $3.25 for each payment up to $150.
- Mail your payment directly to Union Gas.

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

The Late Payment fee is not applied to unpaid security deposit amounts.

Payments are posted to customer accounts based on the day the payment is received. The date of receipt of mailed payment will be the postmark date on the envelope.

4.5 Allocation of Payments between gas and non-gas charges

Payments are applied to charges based on date (oldest paid first), then based on the priority for additional charges incurred at the same time.

For any charges in arrears, payment will be applied to the oldest charge first and Late Payment fees will be applied to the outstanding balance.

Union Gas does not provide joint billing services for rentals or third party services.

4.6 Correction of Billing Errors

If a billing error occurs, customers should contact our Customer Contact Centre at 1-888-774-3111 to request a billing investigation.

With the exception of tampering or theft of gas:

- If the error resulted in over-billing, it will be corrected for a period of up to two years. The customer may request a refund or opt to leave the credit amount on their account to cover future bills.
- If the error resulted in under-billing, it will be corrected for a period of up to one year. If required, Union Gas will work with the customer to determine a mutually agreeable repayment schedule.
- If the time period cannot be reasonably determined, the error will be corrected for a period of up to three months.

4.7 Equal Billing Plan

The Equal Billing Plan offers residential customers the convenience of equal payments throughout the year. Using your total natural gas usage for the previous year and current gas rates, we calculate your total expected gas bills and divide it into equal monthly instalments. In August of each year your EBP is “trued up” and your account is credited or billed for any difference between the EBP instalments that you have paid and the gas you’ve used.

Your account is reviewed periodically and your monthly EBP instalment may be adjusted up or down. Factors that can impact your EBP instalment include significant changes in the weather, gas rates or the amount of gas used.

If you cancel the Equal Billing Plan before the August true up, or if you move from your residence, the plan will be automatically trued up at that point and your account will be billed or credited for the difference between the EBP instalments paid and the cost of the gas you have used.

Each August, your gas usage for the previous year is reviewed to determine your new instalment amount for the coming plan year. You will be automatically re-enrolled in the plan in September for the next 12 months at your new monthly instalment amount.

4.8 Discontinuance of Gas Delivery – Customer Initiated

Customers who require a temporary disconnection of their gas service should contact Union Gas at 1-888-774-3111. During the temporary disconnection, customers must either continue to pay the monthly fixed charge or pay a disconnection and reconnection fee.

4.9 Disconnection for Non-payment

If any charges remain unpaid after the date shown on the invoice, Union Gas has the right to discontinue delivery of gas service.

Residential Accounts - If the customer does not initiate action to manage their arrears, delivery may be discontinued after giving 10 days written notification through a Disconnection Notice to the customer. The Disconnection Notice will indicate the earliest and latest date on which the disconnection will occur, provides payment options to avoid the disconnection of service and indicates that the disconnection can take place without further notification to the customer. In determining whether to issue a disconnection notice or to pursue additional payment arrangements with the customer, Union Gas will take into account any paid security deposit that is being held on the customer's account.

Non Residential Accounts - If the customer does not initiate action to manage their arrears, delivery may be discontinued after giving prior notification through a message on the bill or through other written notification to the customer. In addition to a bill message or written notification, Union Gas attempts to reach the customer by telephone prior to issuing a disconnect order.

At any time prior to service disconnection, a customer can make a payment at a financial institution, through Internet or telephone banking or by credit card, to cancel the disconnection order.

If during the disconnection notice period, a third party, who has been designated by the customer, or a registered charity, government agency or social service agency, advises Union Gas that they are attempting to arrange assistance to help the customer pay their outstanding arrears, Union Gas will cancel the disconnection order and will delay further action for 21 days. If mutually agreeable payment arrangements are created during this process, but are subsequently missed, the account may be disconnected without further notice.

Once the account is paid in full, including any reconnection charges or security deposit required, Union Gas reconnects gas service for the account within two business days.

4.10 Discontinuance of Gas Delivery for other than Non-payment

If we need to temporarily discontinue delivery of gas for meter maintenance, a meter change or line maintenance, Union Gas will make arrangements with the customer in advance as we will need access to the premises to relight and inspect the gas appliances. For safety reasons, gas service cannot be reinstated until this inspection is completed by one of our qualified technicians.

Note: *The above inspections are free, however, if the inspection is carried out at the request of a third party (i.e., lawyer, real estate broker, etc.) then the customer will be charged for the inspection.*

We may **discontinue service at any time for emergency or safety reasons** including:

- a gas leak or potential safety issue in your neighbourhood
- fraudulent use of gas
- any condition affecting appliances or piping which we believe is dangerous to life or property
- the use of gas for any purpose other than that described in the service application, gas sales contact, rate schedule or these rules and regulations
- if we are refused access for any lawful purpose to the premises to which gas is supplied
- when a customer tampers with, damages or destroys our property on their premises

4.11 Security deposits

If you are a new customer to Union Gas or if future payment cannot be assured, you are required to provide a security deposit.

Residential Customers - The deposit will be equal to two of the average month's gas usage based on the last 12 months usage history. Customers are provided the option to pay the security deposit over a maximum of six monthly instalments without interest.

In the majority of cases, Union Gas will waive the security deposit if the customer enters into both the Equal Billing Plan and the Automatic Payment Plan or provides a letter of reference with a good rating from a Canadian natural gas or hydro utility dated within the past 60 days.

Deposits are automatically refunded with interest to the customers' account once the deposit has been paid in full and the customer has exhibited twelve months of good payment history. When the deposit is applied, the customer has the option of leaving the credit amount on their account for future bills or requesting a refund.

Non-Residential Customers - The deposit amount will be a maximum of the three highest consecutive months' usage history or $500.00 if there is insufficient historical usage information for the premises. The deposit is refunded with interest after five years of exhibiting financial stability through a good payment history.

The security deposit may be waived if the customer meets certain criteria.

Acceptable types of security deposits are as follows:

- Money orders or certified cheques
- Letter of Guarantee such as a guarantee of customer payment by a financial institution.

If you do not provide the requested security deposit, delivery of gas will be discontinued. Once the account is paid in full, including the outstanding security deposit, the reconnection charge and any arrears, Union Gas will reconnect the gas service within two business days.

All monetary deposits earn simple interest based on the current bank savings rate. The interest is calculated monthly.

When the customer moves or discontinues gas service, the security deposit is applied to the customer's account.

4.12 Arrears Management Programs

Union Gas has arrears management programs available to customers who are unable to pay their gas charges. Union Gas works with customers to find mutually agreeable payment plans that could extend up to several months depending on the individual circumstances. Customers requiring payment assistance can contact a Union Gas representative at our contact centre by telephoning 1-888-774-3111.

Union Gas will contact the customer, to remind them of required payments under an agreed upon payment arrangement 10 days prior to cancellation of the arrangement and further collection action.

Customers are advised at the time of the arrangement the importance of keeping the payments up to date to avoid further collection action.

4.13 Management of Customer Accounts

Union Gas will verify the identity of a customer prior to discussing account specific information. In accordance with applicable privacy laws, any personal information related to the account will only be shared with the party named as the customer on the account, unless written or verbal consent is provided by the party named as the primary customer on the account.

Union Gas will accept notification to transfer service to a third party name from vendors, purchasers, builders, vendor or purchaser solicitors, power of attorney or property owner/manager or housing administrator. Landlord instructions are maintained with direction from the owner on the management of gas service during a property vacancy and this direction is followed in the absence of a tenant contract. We do not accept new tenant information from vacating tenants.

4.14 Customer Complaint Policy

Step 1: Call Union Gas

Call the Union Gas Customer Contact Centre at 1-888-774-3111, Monday through Friday between 8:00 a.m. and 6:00 p.m. All Union Gas representatives are trained to help answer your questions.

You may also send us an email at uniongas.com/residential/contactus

Step 2: Escalating your Concern

If you have a problem or concern that has not been satisfactorily resolved by our representatives, you may ask to further escalate your concern. Please be advised that you will be required to leave your name and a phone number where you can be contacted. A Union Gas representative will return your call within 2 business days.

Step 3: Submit your Complaint in Writing

Union Gas will respond to all written customer complaints by e-mail or in writing (unless otherwise agreed to by the customer) within 10 calendar days.

Written complaints can be mailed to:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario
N7M 5M1

For further information on our written complaints policy, please visit Customer Complaint Policy.

If your problem has not been resolved to your satisfaction, you can contact the OEB.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Page 19

Account No. 179-120 International Financial Reporting Standards ("IFRS") Conversion Costs.

Please provide details on the amounts shown on the line "revenue requirement" for years 2010 through 2014 on Table 4 (page 19).

Response:

Please see the response at Exhibit B2.7.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Page 22

179-124 Harmonized Sales Tax

Please provide excerpts of the relevant parts of the tax legislation (regulations) referred to on pages 22 to 25, which underpin the creation of capital and O&M savings for Union.

Response:

Capital and O&M savings are a result of PST that would have been paid prior to July 1, 2010 and expensed by Union which is now subject to an input tax credit. These savings are netted against increased costs due to restricted OHST charges where there was previously no PST paid.
HST is governed by the Excise Tax Act in Canada. The Excise Tax Act was amended in December 2009 by Bill C-42 to harmonize Ontario's 8% PST effective July 1, 2010. The relevant section of the Excise Tax Act is included below.

(4) Subsection 123(1) of the Act is amended by adding the following in alphabetical order:

"harmonization date" for a participating province means

(*a*) April 1, 1997 in the case of Nova Scotia, New Brunswick, Newfoundland and Labrador, the Nova Scotia offshore area or the Newfoundland offshore area,

(*b*) July 1, 2010 in the case of Ontario or British Columbia, and

(*c*) the prescribed date in the case of another participating province;

GST/HST Technical Information Bulletin B-104 *Harmonized Sales Tax – Temporary Recapture of Input Tax Credits in Ontario and British Columbia* (Attachment 1) provides an overview of the restrictions placed on specified property or service that is acquired for consumption or use. Page 3 of Attachment 1 provides a definition to specified property or service to include energy and fuel.

Filed: 2012-06-08
EB-2012-0087
Exhibit B3.4
Attachment 1

GST/HST Technical Information Bulletin

B-104 June 2010

Harmonized Sales Tax – Temporary Recapture of Input Tax Credits in Ontario and British Columbia

The information in this bulletin does not replace the law found in the *Excise Tax Act* and its Regulations. It is provided for your reference. As it may not completely address your particular operation, you may wish to refer to the *Excise Tax Act* or its Regulations, or contact a Canada Revenue Agency (CRA) GST/HST rulings office for more information. A ruling should be requested for certainty in respect of any particular GST/HST matter. Pamphlet RC4405, *GST/HST Rulings – Experts in GST/HST Legislation*, explains how to obtain a ruling and lists the GST/HST rulings offices. If you wish to make a technical enquiry on the GST/HST by telephone, please call 1-800-959-8287.

If you are located in Quebec and wish to make a technical enquiry or obtain a ruling related to the GST/HST, please contact Revenu Québec at 1-800-567-4692. You may also visit their Web site at www.revenu.gouv.qc.ca to obtain general information.

Table of Contents

La version française de la présente publication est intitulée *Taxe de vente harmonisée – Récupération temporaire des crédits de taxe sur les intrants en Ontario et en Colombie-Britannique*.

Canada Revenue Agency | Agence du revenu du Canada

Canada

Overview

The Government of Ontario and the Government of British Columbia are each introducing a harmonized sales tax (HST) which will come into effect on July 1, 2010. The HST rate in Ontario will be 13% of which 5% will represent the federal part and 8% the provincial part. The HST rate in British Columbia will be 12% of which 5% will represent the federal part and 7% the provincial part.

This bulletin provides a general description of a temporary restriction on certain input tax credits (ITCs) for large businesses, which in this Bulletin will be referred to as the recapture of input tax credits (RITC) requirement, or recaptured ITCs, that will be implemented under Part IX of the *Excise Tax Act* (the Act). The RITC requirement will be similar to the existing restriction on input tax refunds (ITRs) for large businesses under *An Act Respecting the Québec Sales Tax*.

From July 1, 2010, until June 30, 2018, with the introduction of the HST in Ontario and British Columbia, large businesses – generally those making taxable supplies worth more than $10 million annually, and certain specified financial institutions – will be required to repay or "recapture" the portion of any available input tax credits (ITCs) that is attributable to the provincial part of the HST that becomes payable, or is paid without having become payable, in respect of a specified property or service that is acquired, or brought into one of these provinces, by a large business for consumption or use by that business in those provinces.

Persons subject to the RITC requirement will not be allowed to simply forego claiming these recaptured ITCs in their calculation of net tax. Instead, they will be required to separately identify any recaptured ITCs in their GST/HST NETFILE returns. It is important to note that, in this particular respect, the RITC requirement will be different from the existing restriction on ITRs in Quebec.

The rate of ITC recapture will be 100% for the first five years that the HST is in effect in Ontario and British Columbia. The RITC requirement will then be phased out by reducing the rate of recapture in equal increments over the following three years. The ITC recapture rates will be as follows:

Period	ITC recapture rates
July 1, 2010 to June 30, 2015	100%
July 1, 2015 to June 30, 2016	75%
July 1, 2016 to June 30, 2017	50%
July 1, 2017 to June 30, 2018	25%
On or after July 1, 2018	0%

Interpretation

Unless otherwise noted, the terms and concepts used in this bulletin generally have the same meaning as they do for the purposes of Part IX of the Act. In addition, the following terms have the following meanings:

- **"recapture period"** means a one-year period that (a) begins immediately after June 30 of a particular calendar year and ends immediately before July 1 of the following calendar year, and (b) occurs during the period that the RITC requirement is in effect (i.e., during the period on or after July 1, 2010 and before July 1, 2018); and
- **"specified property or service"** generally means a qualifying motor vehicle, energy, a telecommunication service, a meal or entertainment, that is acquired, or brought into Ontario or British Columbia, by a large business for consumption or use by that business in those provinces, and for Ontario only, fuel (other than diesel) that is acquired or brought into Ontario by a large business for consumption or use by that business in Ontario. The particular circumstances in which the RITC requirement will apply to specified property and services are described in other parts of this bulletin.

Large businesses

In general, only a person that is considered to be a large business will be subject to the RITC requirement. For the purposes of the RITC requirement, a person is considered to be a large business during a particular recapture period if the person is a GST/HST registrant and:

- the person's RITC threshold amount (which is explained below under the heading The RITC Threshold Amount) for that recapture period is greater than $10 million, or
- the person is one of the following financial institutions (other than a selected listed financial institution), or a person that is related (for purposes of the Act) to one of the following financial institutions (hereafter a "specified financial institution"): a bank; a corporation that is licensed or otherwise authorized under the laws of Canada or a province to carry on in Canada the business of offering to the public its services as a trustee; a credit union; an insurer or any other person whose principal business is providing insurance under insurance policies; a segregated fund of an insurer; an investment plan or the Canada Deposit Insurance Corporation.

A selected listed financial institution will not be considered a large business.

A person that otherwise meets the criteria would be considered to be a large business regardless of whether the person has a permanent establishment in Ontario or British Columbia.

A public service body will not be considered to be a large business. Similarly, a person whose chief source of income is farming, as defined in the federal *Income Tax Act*, will generally not be considered to be a large business to the extent that the person is acquiring, or bringing into Ontario or British Columbia, a specified property or service for use or consumption in farming activities.

The following government entities will not be considered large businesses:

- An entity of the government of Canada that is not listed in Schedule I of the *Federal Provincial Fiscal Arrangement Act,*
- a department (as defined in section 2 of the *Financial Administration Act)* or
- an entity of the government of a province, that is eligible, pursuant to a provision of a sales tax harmonization agreement with that province, for a rebate of the GST/HST.

If a partnership is a large business and a member of the partnership (other than an individual) acquires, or brings into Ontario or British Columbia, a specified property or service for use in one of these provinces, and that use is in respect of the activities of the partnership (but not on account of the partnership), the member will

generally be considered to be a large business in respect of that acquisition or bringing in, if at that time, the member is a GST/HST registrant.

If a participant in a joint venture is a large business that has made a joint venture election with the operator of the joint venture, and the operator acquires, or brings into Ontario or British Columbia, a specified property or service on behalf of the participant for consumption or use in one of these provinces, the operator will generally be considered to be a large business in respect of that acquisition or bringing in.

The RITC threshold amount

For the purposes of determining whether a particular person is a large business for a particular recapture period, the RITC threshold amount of the person for that particular recapture period will include the following amounts:

(a) the total of all consideration for taxable supplies made in Canada, or outside Canada through a permanent establishment in Canada, by the person that became due, or was paid without having become due, in the last fiscal year of the person that ended before the recapture period;

(b) the total of all consideration for taxable supplies made in Canada, or outside Canada through a permanent establishment in Canada, by a GST/HST registrant that is associated (for purposes of the Act) with the particular person, that became due, or was paid without having become due, in the last fiscal year of the associated person that ended before the recapture period, and

(c) where, at any time in the 12-month period before the recapture period, the particular person purchased a business from another person that would be a large business in the absence of paragraph (b), and under the agreement for the supply, acquired all or substantially all the property necessary for the particular person to carry on that business, the total of all amounts as determined by the following formula:

$$(E/F) \times (365 - G)$$

where

"E" is the total of all consideration for taxable supplies made in Canada or made outside Canada through a permanent establishment in Canada by that particular person that became due or was paid to the person in relation to that business acquired by the person,

"F" is the number of days in the 12-month period immediately preceding the recapture period that are after that time, and

"G" is the number of days in the 12-month period immediately preceding the recapture period that are after that time and that are in the fiscal year referred to in paragraph (a).

In calculating the amount of consideration described in (a), (b) and (c) above, the following amounts should be included:

- any amount by which consideration for a supply is reduced because of a trade-in of tangible personal property by the recipient of the supply,
- consideration that is attributable to a supply made by a specified member of a qualifying group to another specified member of the same qualifying group, to the extent that the supply is deemed under the Act to have been made for no consideration, and
- the fair market value of a supply made between persons not dealing at arms length, to the extent that the consideration for the supply is less than fair market value.

However, in calculating the amount of consideration described in (a), (b) and (c) above, the following amounts should not be included:

- an amount attributable to the GST/HST, or to a provincial levy that is prescribed for the purposes of the Act (e.g., a provincial retail sales tax);
- an amount attributable to a supply by way of sale of real property that is capital property of the supplier;
- an amount attributable to a supply of a financial service; and
- an amount that is attributable to goodwill that is supplied as part of the supply of a business.

In calculating the amount of consideration described in (b) above, a person must include consideration attributable to taxable supplies made by an associated person that is not itself considered to be a large business (e.g., an associated person whose chief source of income is farming).

If a person or its associates has a fiscal year that is shorter or longer than 365 days, the $10 million threshold will be adjusted to reflect the length of the fiscal year.

Example 1

Business D is associated with Business Y, whose chief source of income is farming as defined in the *Income Tax Act* and who engages exclusively in farming activities. Both companies have a December 31 fiscal year end, and their RITC threshold amount for the 2010 fiscal year is $12 million. To the extent that Business Y engages exclusively in farming activities, only Business D would be considered a large business for the recapture period of July 1, 2011 to June 30, 2012.

Example 2

Company C has a fiscal year ending December 31, 2010. However, that fiscal year was only 182 days long, and its RITC threshold for that fiscal year was $6 million. Company C would need to adjust this amount to determine what the RITC threshold would be for a full fiscal year. Since this amount exceeds $10 million ($6 million × 365/182 days = $12 million), Company C would be a large business for the recapture period of July 1, 2011 to June 30, 2012.

Example 3

Corporation X has a fiscal year end of April 30, 2010. Its RITC threshold for that fiscal year was $11 million. In August 2010, it sells one of its divisions that had taxable supplies of $3 million. Corporation X is a large business for the recapture period of July 1, 2010 to June 30, 2011. For the fiscal year ending April 30, 2011, Corporation X's RITC threshold is $9 million. Corporation X will not be a large business for the recapture period of July 1, 2011 to June 30, 2012.

Changes during a recapture period

If a person that is not a large business at the beginning of a particular recapture period has a fiscal year end during that recapture period and its threshold amount exceeds $10 million at that point, the person will generally not be considered to become a large business until the beginning of the next recapture period. Conversely, if a person that is a large business at the beginning of a particular recapture period has a fiscal year end during that recapture period and its threshold amount is below $10 million at that point, the person will generally continue to be considered to be a large business until the end of that recapture period.

Example 4

Company XYZ has a fiscal year that ends on December 31, 2010 and its threshold amount during that fiscal year is $7 million. Company XYZ would not be a large business during the recapture period of July 1, 2011 to June 30, 2012. At the end of its 2011 fiscal year, Company XYZ's RITC threshold is $11 million. Company XYZ would be a large business beginning July 1, 2012, for the recapture period of July 1, 2012 to June 30, 2013.

If the threshold amount of a person that becomes a GST/HST registrant is greater than $10 million at the time when it becomes a registrant, due to the taxable supplies of its associated persons, the person will generally be

considered to become a large business, and will be required to begin recapturing ITCs, at that time. It would remain a large business until the end of the current recapture period.

Example 5

ABC Company incorporated on June 1, 2011, and registered for GST/HST on June 15, 2011. At the time of registration on June 15, ABC is associated with other companies whose RITC threshold amount is $15 million dollars. ABC is a large business beginning June 15, 2011, and would begin recapturing ITCs at that time. It would remain a large business until the end of the current recapture period.

If a particular corporation that is a large business acquires control of another corporation that is not a large business, the other corporation (and any associated persons) will generally be considered to become a large business when that control is acquired and will be required to begin recapturing ITCs at that time. It would remain a large business until the end of the current recapture period

Example 6

All the shares of Corporation C, which is not a large business, are purchased by Large Business A. At the time of this purchase, Corporation C becomes a large business and would begin recapturing RITCs at that time. It would remain a large business until the end of the current recapture period.

If two or more corporations amalgamate and the combined threshold amounts of those corporations are greater than $10 million at that time, the amalgamated corporation will generally be considered to become a large business upon amalgamation and will be required to begin recapturing ITCs at that time. It would remain a large business until the end of the current recapture period

Example 7

Corporation Y and Corporation Z amalgamate on June 15, 2011, to become Corporation YZ. The combined RITC threshold amounts of both corporations exceed $10 million. Therefore, Corporation YZ is a large business on June 15, 2011, and would begin recapturing RITCs at that time. It would remain a large business until the end of the current recapture period.

If a particular person that is not a large business purchases a business of another person that would be a large business in the absence of paragraph (b) of the RITC threshold , and under the agreement for the supply of the business, the particular person acquires all or substantially the property necessary for the particular person to continue to carry on the business of that other person, the particular person will generally be considered to become a large business at the earlier of (a) the time that it begins to carry on the business, and (b) the time that it acquires substantially all of the property, and will be required to begin recapturing ITCs at that earlier time.

Example 8

On August 15, 2012, Company B that is not a large business acquires a business from Company A, that would be a large business, without reference to its associate's taxable supplies. Under the agreement for the supply of this business, Company B has acquired all or substantially all the property needed to carry on the business starting September 15, 2012. Company B will be considered a large business effective August 15, 2012 and would begin recapturing ITCs at that time. It would remain a large business until the end of the current recapture period.

Before the beginning of the next recapture period, Company B would take the value of the taxable supplies it made from this business into account in determining its RITC threshold for that next recapture period. For example, assume that in the 12-month period before the recapture period beginning July 1, 2013, Company B's taxable supplies from this new business, as determined under paragraph (c) of the definition of the RITC threshold, is $6 million. If company B's fiscal year end for 2012 is December 31, it would include $4.27million* when calculating its RITC threshold for the recapture period of July 1, 2013 to June 30, 2014.

* {$6million / 319 days (August 16, 2012 to June 30, 2013) × [365 – 138 days (August 16, 2012 to Dec. 31, 2012)]}

Example 9

Company A, Company B, and Company C are associated and have a combined RITC threshold amount of $12 million. Company X, which is not a large business and has an RITC threshold amount of $4 million, purchases a business of Company A (whose threshold amount alone (i.e.,

without reference to paragraph (b) of the RITC threshold) is $3 million). Under the agreement for the supply of the business, Company C has acquired all or substantially all the property needed for Company X to carry on that business. Company X will not be considered a large business at that time. However, Company B and Company C will remain large businesses until the end of the recapture period.

Example 10

In May 2010, Company A, a large business with a December 31 year-end, sells property of one of its branches to Company B, which is not a large business. Under the agreement for the supply of the business, Company B is not acquiring all or substantially all of the property needed by Company B to carry on the business. Company A will remain a large business for the recapture period of July 1, 2010 to June 30, 2011. If, for the fiscal year ending December 31, 2010, Company A's RITC threshold is $9 million, Company A will not be a large business for the recapture period of July 1, 2011 to June 30, 2012.

At the time of the purchase of the property of Company A's branch, Company B was not a large business, and will continue not to be a large business, until the recapture period following a fiscal year when its RITC threshold amount exceeds $10 million.

If a person becomes a specified financial institution (which does not include selected listed financial institutions), or becomes related to one at a particular time, the person would generally be considered to become a large business at that time (and continue to be one until it ceases to be a specified financial institution or ceases to be related to one), and would be required to begin recapturing ITCs at that time.

Example 11

Corporation F is a newly incorporated company. All the shares of Corporation F are owned by Corporation B, a company whose principal business is selling insurance. Since Corporation F is related to Corporation B, a specified financial institution, Corporation F is a large business.

Specified property and services

The RITC requirement will generally apply to specified property and services that are acquired, or brought into Ontario or British Columbia, by a large business for consumption or use by that business in these provinces. Property and services that are acquired in Ontario or British Columbia for consumption or use outside these provinces will generally not be subject to the RITC requirement.

In general, specified property and services include:

- qualifying motor vehicles, including certain vehicle parts and services, and in Ontario, motive fuel (other than diesel fuel) for use in motor vehicles;
- specified energy;
- specified telecommunication services; and
- specified meals and entertainment that are currently subject to an ITC repayment requirement of 50% under the Act.

However, the RITC requirement would generally not apply to the following specified property and services:

- specified property acquired by a large business for the sole purpose of being resupplied by that large business (i.e., either by way of sale, or by way of lease, licence or similar arrangement),
- specified property acquired by a large business for the sole purpose of it becoming a component part of other tangible personal property that is to be supplied by the large business, or
- a specified service that is acquired by a large business for the sole purpose of being resupplied by that business.

The particular circumstances in which the RITC requirement will apply to specified property and services are described in more detail below.

Qualifying motor vehicles

A qualifying motor vehicle will generally mean a vehicle that:

- is a motor vehicle;
- is licensed, or required to be licensed, under applicable provincial laws for use on a public highway (a vehicle that is licensed, or required to be licensed, exclusively for use elsewhere than on a public highway would generally not be considered to be a qualifying motor vehicle); and
- weighs while carrying its maximum capacity of fuel, lubricant and coolant, less than 3,000 kg at the time that the vehicle is first licensed or required to be licensed in Ontario or British Columbia, as the case may be.

For the purposes of the definition of a qualifying motor vehicle, a motor vehicle means a motorized vehicle designed for the transportation of individuals or of tangible personal property, but does not include:

- a power-assisted bicycle;
- a snow vehicle;
- an all-terrain vehicle;
- an electrically propelled wheelchair;
- a street car;
- a vehicle that runs only on rails, or
- a farm tractor, or other farm machinery, acquired, or brought into a province, exclusively for use in farming activities.

Qualifying motor vehicles will include vehicles that are acquired by way of sale, or by way of lease, licence or similar arrangement (including short-term rentals). However, a taxi permit-holder entrusting the operation and custody of a taxi to another person would not be considered to be an acquisition of a qualifying motor vehicle by that other person.

Example 12

A pick-up truck, that weighs less than 3,000 kg, is required to be licensed in Ontario for use on public highways. The pick-up truck is a qualifying motor vehicle.

An all-terrain recreational vehicle is not a motor vehicle for the purposes of RITCs and consequently it is not a qualifying motor vehicle.

Parts and services

The RITC requirement will apply to vehicle parts and services that are acquired, or brought into Ontario or British Columbia, by a large business in respect of a qualifying motor vehicle if the parts and services are acquired or brought in within 12 months of the acquisition, or bringing into one of these provinces, of the vehicle itself (even if the vehicle was acquired or brought into these provinces before July 1, 2010), for example, the acquisition and installation of a vehicle anti-theft system. However, the RITC requirement will generally not apply to vehicle parts and services that are acquired, or brought into these provinces for the routine repair or maintenance of a qualifying motor vehicle of the business.

Example 13

In October 2010, a large business purchases an automobile that is a qualifying motor vehicle. In May 2011, air conditioning is installed in the automobile. The RITC requirement will apply to the installation of the air conditioning.

Example 14

In May 2010, a large business purchases an automobile that is a qualifying motor vehicle. In July 2011, air conditioning is installed in the automobile. Since the installation of the air conditioning does not occur within 12 months of the purchase of the qualifying motor vehicle, the RITC requirement does not apply to the installation.

Example 15

In October 2010, a large business purchases an automobile that is a qualifying motor vehicle. Six months later, the large business pays for an oil change for the vehicle. The RITC requirement does not apply to the oil change.

Use of qualifying motor vehicles before resupply

The RITC requirement will generally not apply in cases where a large business acquires, or brings into Ontario or British Columbia, a qualifying motor vehicle for the sole purpose of resupplying the vehicle. However, if the large business uses such a vehicle before resupplying it, the large business will generally be required to recapture a portion of the ITCs that it was entitled to claim in respect of the acquisition or bringing in of that vehicle. The large business will be required, for each month or part thereof that it uses the vehicle in a fiscal year to recapture the portion of the provincial part of the ITC that is attributable to 2% of the cost of the vehicle. This recapture is to be reported in the GST/HST return for the reporting period that includes the last day of that fiscal year.

Example 16

A large business acquires a vehicle in British Columbia for the purpose of leasing the vehicle to other persons. The ITC available on the acquisition of the vehicle is not subject to recapture.

Example 17

In April 2011, a car dealership in British Columbia that is a large business acquires, for the purpose of resale, a vehicle that costs $20,000 and claims ITCs in respect of that acquisition (i.e., with no recapture). The dealership subsequently uses the car as a demo vehicle for two months before selling it. In its GST/HST return for the reporting period that includes the last day of that fiscal year, the dealership must recapture $56 of the ITCs claimed in respect of the acquisition of that vehicle: $20,000 (cost) × 2% × 7% (provincial part of HST) × 2 months = $56.

Fuel for use in qualifying motor vehicles in Ontario

The RITC requirement will also generally apply to fuel (other than diesel fuel) that is acquired, or brought into Ontario, by a large business, to the extent that the fuel is for use by that business in the engine of a qualifying motor vehicle (even if the that vehicle was acquired, or brought into Ontario, prior to July 2010).

Example 18

A large business in Ontario operates a parcel delivery business. All of the motor vehicles that it owns are qualifying motor vehicles, and these vehicles use gasoline as fuel. The RITC requirement applies to the purchase of the gasoline as fuel for these vehicles.

Example 19

A car dealership in Ontario that is a large business acquires motor vehicles for the purposes of resale. The RITC requirement does not apply to the acquisition of these vehicles. In addition, when the car dealership purchases gasoline for these vehicles (for example, in order for customers to take these vehicles for test drives), the RITC requirement will not apply to these gasoline purchases.

Specified energy

Specified energy will generally include the following when acquired, or brought into Ontario or British Columbia, for consumption or use in these provinces by a large business:

- electricity, gas, steam, and

- anything (other than fuel for use in a propulsion engine)[1] that can be used to generate energy
  - by way of combustion or oxidization, or
  - by undergoing a nuclear reaction in a reactor for the generation of energy.

For purposes of the RITC requirement, consideration for a single supply of specified energy will include the consideration attributable to transportation services and fees (e.g., delivery charges or regulatory fees) that are incidental to the supply of energy itself. Conversely, consideration for a supply of specified energy will generally not include consideration for transportation services that are not incidental to the supply of energy itself.

Example 20

A large business purchases natural gas from a supplier in British Columbia for use in British Columbia. The invoice for the natural gas also includes delivery charges. Since the delivery charges are incidental to the purchase of the natural gas, the total consideration for the supply of the natural gas will include the consideration attributable to the delivery charge.

Example 21

A large business purchases electricity in Ontario for use in Ontario. The invoice for the electricity is issued from a local distribution company, and shows the separate supplies of electricity made by the retailer of the electricity and the supplies of distribution services made by the local distribution company, both of which occur simultaneously. Since the supplies are made by different suppliers, the tax payable for the consideration for the supply of electricity from the retailer will be subject to the RITC requirement. However, the consideration payable for the distribution services is not part of the consideration payable for the energy, and consequently, the tax payable for this consideration is not subject to the RITC requirement.

The RITC requirement will generally not apply to specified energy acquired by a sponsor or organizer of a convention for use exclusively at that convention. In addition, the RITC requirement will generally not apply to specified energy used to heat asphalt that is for use in the construction or maintenance of an eligible roadway.

An eligible roadway is a road, highway, bridge, tunnel, ferry landing or ferry approach that is for the passage of vehicles, but does not include a dedicated parking area, an airport runway, a shipyard, a driveway or a bicycle or pedestrian pathway.

Example 22

An organizer of a domestic convention pays for electricity that will be for use exclusively at the convention held in Toronto. The RITC requirement does not apply to the purchase of the electricity.

Specified energy acquired by a lessee as part of a single supply of a real property lease will not be subject to the RITC requirement (as the lessee will not, for purposes of the GST/HST, be acquiring a supply of energy). Conversely, a lessor that provides energy to a lessee as part of a single supply of a real property lease will not be able to claim relief from the RITC requirement on the basis of the manner in which the lessee uses that energy, for example, if the lessee uses the energy directly in the production of tangible personal property for sale.

Example 23

A lessor that is a large business leases a building to a lessee, also a large business. The lessee uses the building to produce widgets for sale. As part of the supply of the lease for the building, the lessor charges the lessee an amount for heat (natural gas). Since the lessor is providing the heat as part of a single supply of a lease of real property, the lessee is not subject to the RITC requirement. In addition the lessor will not be able to claim relief for the RITC requirement for specified energy, even though the lessee uses part of this energy directly in the production of widgets for sale.

[1] However, fuel for use in the engine of a motor vehicle may be subject to the RITC requirement for Ontario. Please see the section entitled "Qualifying Motor Vehicles" in this bulletin.

Production for sale

The RITC requirement will generally not apply to specified energy used by a large business directly in the production of:

- tangible personal property for sale, or
- production equipment or conditioning materials used by the large business in the production of tangible personal property for sale.

The RITC requirement will, however, generally apply to specified energy that is used by the large business to facilitate such production (i.e., and not directly in the production process), including specified energy that is used to light, heat, air condition or ventilate a production facility.

Example 24

Large Business A (LBA), which sells widgets, acquires electricity for use in one of its production facilities in British Columbia. The electricity is used to operate the widget producing machines, to provide light, heat and ventilation in the building, to operate a building security system, to run appliances in a dining area in the building, and to control the temperature in a storage area for the widgets.

The RITC requirement will not apply to the electricity used in the production building to the extent that the electricity was used to operate the widget producing machines (because that electricity is used directly in the production process). However, the RITC requirement will apply to the portion of the electricity used otherwise than in the operation of the widget producing machines (because that electricity is not used directly in the production process).

The RITC requirement will generally apply to specified energy that is used by a large business to produce tangible personal property that is used:

- otherwise than for sale, such as energy used by the large business to produce furniture that is used as capital personal property by the large business;
- in the construction of real property (including mobile homes and floating homes) of the large business, including real property that is (a) capital property of the large business or (b) for sale by the large business; or
- in the course of supplying services or intangible personal property.

Example 25

A large business supplies catering services. The specified energy that it uses in preparing the meals, etc., is subject to the RITC requirement.

The RITC requirement will generally not apply to specified energy used by a large business to produce another form of energy that is used in a manner whereby the RITC requirement would not apply if the energy were used directly.

Example 26

If, in Ontario, diesel fuel was used in a generator to produce electricity that was used directly in the production of tangible personal property for sale, the RITC requirement will generally not apply to the portion of the diesel fuel that is attributable to the electricity subsequently used directly in the production of tangible personal property for sale.

Production and production equipment

For purposes of the RITC requirement, "production" will generally mean the assembling, processing or manufacturing of tangible personal property to make other tangible personal property that is different from the first property by its nature or characteristics, and will include:

- the restoring of tangible personal property by its owner,
- the recording of images or sounds on media,
- the generation of any form of energy or its transformation into another form of energy ,

- the cutting, transformation and handling of timber in a forest, including the building and maintenance of forest access roads in the course of carrying on a timber business,
- the extraction and processing of minerals to the first stage of concentration or the equivalent, and
- the transformation of toxic industrial waste into a non-toxic product.

Production will also generally include the following activities when performed in conjunction with one of the production activities described above:

- the cleaning, screening, sifting, wrapping, packing or putting into containers of personal property;
- the transportation of refuse or waste derived from producing personal property,
- the quality control of personal property being produced or of production equipment, and
- the detection, measurement, treatment, reduction or elimination of water, soil or air pollutants that are attributable to producing personal property.

However, "production" will generally not include (a) the storage of finished products or (b) the assembly, processing or manufacturing of tangible personal property in a retail establishment. For purposes of the RITC requirement, "production equipment" will generally mean

(a) machinery, tools, equipment and accessories used directly in the production of tangible personal property,:

(b) moulds and dies,

(c) media for recording images or sounds,

(d) plans, drawings, models and prototypes,

(e) components or spare parts of the property described in paragraphs (a) to (d),

(f) materials used to produce or repair the property described in paragraphs (a) to (e), and

(g) explosives and the material to manufacture them.

For purposes of the RITC requirement, specified energy used by the following kinds of businesses will generally not be considered to be used in the production of tangible personal property for sale:

- financial institutions,
- hotels, bars, coffee shops and restaurants,
- auto repair shops, and
- scrap metal dealers.

Example 27

Specified energy used by a restaurant to brew coffee and prepare meals will not be considered to be used in the production of tangible personal property for sale.

Production proxy

To simplify compliance with the RITC requirement, a large business producing tangible personal property in Canada for sale (and in its last fiscal year carried on such Canadian production activities at least 10% in British Columbia or primarily in Ontario) will generally be able to elect to use a production proxy to determine what portion of the specified energy that it acquires for use in these provinces will be considered to be used directly in the production of tangible personal property for sale (and hence not subject to the RITC requirement), and consequently, what portion of the provincial component of the HST payable on the energy costs is subject to recapture.

The election Form RC4530, *Election or Revocation of an Election to Use a Production Proxy to Report the Recapture of Input Tax Credits*, will have to be filed with the CRA by the due date of the GST/HST return for the first reporting

period in a particular recapture period and will generally apply for that entire recapture period. The election will remain in effect until revoked, and can only be revoked if used for a minimum of one recapture period.

This production proxy will be based on the Canadian detail of the North American Industry Classification System for 2007 ("NAICS Canada 2007"), which is a statistical tool that classifies particular sectors, subsectors and industries into categories based on production oriented principles.

Specifically, if the most significant business activity of a large business in its last fiscal year fell into one of the 24 categories described below (which are based on NAICS Canada 2007 categories), it will be eligible to use, in the current recapture period one of three fixed percentages to determine the portion of the total amount of specified energy that it acquires for use in Ontario or British Columbia that will **not** be considered to be used directly in the production of tangible personal property for sale. These percentages reflect the average proportion of energy that is not used directly in such production activities in a particular industrial sector.

- For a large business whose most significant business activity in its last fiscal year fell within one of the following categories (the corresponding three-digit NAICS Canada 2007 codes are also provided), the production proxy will be 4%:
    - 113 – forestry and logging;
    - 211 – oil and gas extraction;
    - 212 – mining and quarrying (except oil and gas);
    - 322 – paper manufacturing;
    - 324 – petroleum and coal product manufacturing;
    - 325 – chemical manufacturing;
    - 327 – non-metallic mineral product manufacturing; and
    - 331 – primary metal manufacturing.
- For a large business whose most significant business activity in its last fiscal year fell within one of the following categories, the production proxy will be 13%:
    - 311 – food manufacturing;
    - 312 – beverage and tobacco manufacturing;
    - 313 – textile mills;
    - 314 – textile product mills;
    - 321 – wood product manufacturing;
    - 326 – plastics and rubber products manufacturing; and
    - 332 – fabricated metal product manufacturing.
- For a large business whose most significant business activity in its last fiscal year fell within one of the following categories, the production proxy will be 30%:
    - 315 – clothing manufacturing;
    - 316 – leather and allied product manufacturing;
    - 323 – printing and related support activities;
    - 333 – machinery manufacturing;
    - 334 – computer and electronic product manufacturing;
    - 335 – electrical equipment, appliance and component manufacturing;
    - 336 – transportation equipment manufacturing;
    - 337 – furniture and related product manufacturing; and
    - 339 – miscellaneous manufacturing.

GST/HST registrants that are large businesses whose most significant business activity in its last fiscal year did not fall within any of the foregoing categories (or that did not carry on at least 10% of their Canadian production

activities in British Columbia, or that did not carry on their Canadian production activities primarily in Ontario) will not be entitled to use this proxy for the current recapture period.

Example 28

In its previous fiscal year, a GST/HST registrant, that is a large business that carried on production activities primarily in Ontario, had three different business activities: 25% of its revenues were derived from forestry and logging, 40% from wood product manufacturing, and 30% from furniture manufacturing. The large business determines that its most significant business activity fell under the description of the category 321, wood product manufacturing. Therefore, its production proxy for specified energy will be 13%, and it will recapture 13% of the provincial component paid or payable on its energy costs.

Example 29

A large business publishes a community newspaper in British Columbia, which is provided free of charge to the community. Its revenue is derived from the sale of advertising. Even though the large business is producing the newspaper for sale (for no consideration), the large business's most significant business activity is supplying advertising, which is not one of the categories eligible for using the production proxies. The corporation will use a fair and reasonable method to track the specified energy that it acquires to produce the newspaper and claims ITCs in respect of this specified energy.

Example 30

A large business in British Columbia, whose most significant business activity in its last fiscal year fell within the description of the category of wood product manufacturing (category no. 321) could, instead of tracking the amount of specified energy that it uses in production, file election Form RC4530, *Election or Revocation of an Election to Use a Production Proxy to Report the Recapture of Input Tax Credits*, with the CRA by the due date of the GST/HST return for the first reporting period in a particular recapture period. For each reporting period during that recapture period, 13% of the specified energy that the large business acquires for use in British Columbia will be deemed not to be used directly in the production of tangible personal property for sale. Therefore, it will recapture 13% of the provincial component paid or payable on its energy costs.

Scientific research and experimental development (SR&ED) activities and the SR&ED proxy

The RITC requirement will generally not apply to specified energy used by a large business directly in activities that are qualifying SR&ED activities in Ontario for purposes of the *Taxation Act, 2007* (Ontario) or directly in activities that are SR&ED activities in British Columbia for purposes of the British Columbia *Income Tax Act*. A large business engaged in SR&ED activities in its current taxation year that is eligible for, and actually claims, SR&ED expenditures or investment tax credits for income tax purposes in that taxation year will generally only be required to recapture ITCs other than those available in respect of the specified energy used directly in the qualifying SR&ED activities.

A large business will be able to either track the actual amount of specified energy used directly in qualifying SR&ED activities, or use the following formula (i.e., the SR&ED proxy) to determine what portion of the specified energy will **not** be considered, for purposes of the RITC requirement, to be used directly in qualifying SR&ED activities.

$$A = B/C$$

where:

"A" is the proportion (expressed as a percentage) of the specified energy not considered to be used directly in qualifying SR&ED activities in Ontario or British Columbia;

"B" is the total amount of the portion of the salaries and wages of employees of the large business that were paid by the large business in the second last taxation year of the person and that were not directly engaged in SR&ED activities in Ontario or British Columbia; and

"C" is the total amount of salaries and wages of employees of the large business in Ontario or British Columbia that were paid by the large business in the second last taxation year of the large business.

The resulting amount will be the amount of energy subject to the RITC requirements.

Example 31

A large business has activities that are eligible SR&ED activities in Ontario for purposes of the *Taxation Act, 2007* (Ontario). It will be claiming SR&ED expenditures or investment tax credits for these activities in the current taxation year, and decides to use the proxy formula in respect of the specified energy used directly in the qualifying SR&ED activities. The amounts of salaries and wages used in the proxy formula will be the amounts paid by the large business in its second last taxation year.

An election is required to use this proxy. The election form does not need to be filed with the CRA, but needs to be retained by the large business with its records. The proxy election is valid for the current recapture period, only, and a new election form must be completed for each recapture period for which the proxy method is used.

Ordered application of proxies to specified energy

If a large business is using both the SR&ED proxy and the production proxy, it will apply the first proxy to the specified energy it acquires for use in Ontario or British Columbia, and then apply the other proxy to the residual amount (i.e. instead of adding the two percentages together and applying the sum of these two percentages). This "ordered" approach to applying the proxies to specified energy will help ensure that some portion of that energy will be subject to the RITC requirement (reflecting the fact that some energy will be attributable to other uses, such as overhead).

Example 32

For purposes of the RITC requirement, the most significant business activity of a large business is food manufacturing (category 311) and it is therefore using the 13% production proxy. It is also using a 75% SR&ED proxy (as 75% of the salaries and wages of its employees are not directly engaged in SR&ED activities). In its August 2012 reporting period, the large business has $800 in available ITCs that are attributable to the provincial component of the HST payable in respect of specified energy it acquired during that reporting period. The large business multiplies the $800 by the two proxies ($800 × 75% × 13%) and will, therefore, have to recapture $78 in ITCs in respect of that specified energy

Note that a large business that acquires specified energy that is later resupplied by that business (in addition to specified energy used by that business in producing tangible personal property for sale or in eligible SR&ED activities) will first have to deduct the proportion of its specified energy that is re-supplied from the total specified energy it acquired before applying any proxy.

Specified telecommunication services

Specified telecommunication services will generally include:

(a) the service of emitting, transmitting or receiving signs, signals, writing, images or sounds or intelligence of any nature by wire, cable, radio, optical or other electromagnetic system, or by any similar technical system; and

(b) the making available for such emission, transmission or reception a telecommunications channel, such as a telecommunications circuit, line, frequency, channel, partial channel or other similar means of transmitting a telecommunication (but not a satellite channel)

when acquired for consumption or use in Ontario and British Columbia.

Thus, the RITC requirement will generally apply to services such as:

- local and long-distance telephone,
- cable and pay television,
- satellite television,

- facsimile and electronic mail,
- video, audio and computer link-ups, and
- data transmission acquired by a large business for use in Ontario or British Columbia by that large business.

However, the RITC requirement will generally not apply to:

- internet access services;
- web-hosting services;
- toll-free telephone services (e.g., 1-800, 1-866, 1-888 or 1-877 telephone services) or a telecommunication service related to toll free telephone services; and
- telecommunication services acquired by a sponsor or organizer of a convention for use exclusively at that convention.

Supplies that are provided by means of telecommunication, but are not themselves telecommunication services, will generally not be subject to the RITC requirement. Examples of supplies that are provided by means of telecommunication include:

- building surveillance services,
- news services offered by press agencies,
- a right to access a data bank, and
- services provided by means of a 1-900 telephone service.

Proxies for specified telecommunication services

If a large business receives an invoice for a single supply that includes both specified telecommunication services and other services and/or goods (i.e., that are not subject to the RITC requirement), and the large business cannot readily ascertain which portion of the provincial component of the HST applicable to the supply is attributable to these other services and/or goods, the large business will be allowed to use the following proxies to make that determination.

For Ontario:

1. If the supply covered by the invoice includes specified telecommunication services, other services, and goods (e.g., telecom equipment rental), then 14% of the consideration for the supply will be deemed to be attributable to the other services and goods.
2. If the supply covered by the invoice includes specified telecommunication services and other services (but no goods), then 4% of the consideration for the supply will be deemed to be attributable to the other services.
3. If the supply covered by the invoice includes specified telecommunication services and goods (but no other services), then 11% of the consideration for the supply will be deemed to be attributable to the goods.

For British Columbia:

If the supply covered by the invoice includes specified telecommunication services **and** other services and/or goods (e.g., telecom rental), then 5% of the consideration for the supply will be deemed attributable to the other services and/or goods.

No election is required to be filed to use these proxies.

Specified meals and entertainment

Section 236 of the Act requires GST/HST registrants to recapture 50% of the ITCs they claimed on meal and entertainment expenses that are subject to the 50% deductibility under the *Income Tax Act*. This recapture also

applies to allowances and reimbursements paid by the registrant for these expenses and for which the registrant has claimed input tax credits.

Specified property and services will generally include food and beverages for human consumption (meals) and entertainment that are acquired by a large business in Ontario or British Columbia, to the extent that the meals or entertainment are subject to the existing (generally 50%) ITC recapture requirement in the Act (specified meals and entertainment).

Thus, meals and entertainment subject to the RITC requirement will include:

- business dinners;
- tickets for a theatre, concert, athletic event or other performance;
- private boxes at sports facilities; and
- admissions to nightclubs, athletic, social and sporting clubs.

Conversely, meals and entertainment not subject to the RITC requirement will generally include:

- meals or entertainment acquired solely for the purpose of resupply (e.g., by a restaurant or airline);
- meals or entertainment acquired for certain events where all employees from a particular location are invited (e.g., an office Christmas party); and
- meals or entertainment for an employee in situations where the expenses are required to be included in the employee's income as a taxable benefit under the *Income Tax Act*.

See Example 36.

Meal expenses for long-haul truck drivers

For 2010, meal expenses for long haul truck drivers are deductible under the *Income Tax Act* at 75%, and registrants are required to recapture 25% of the ITC claimed for the tax paid or payable for these meal expenses. After 2010, these percentages will be 80%, and 20%, respectively. Meal expenses for long haul truck drivers will not be specified property and services. Consequently, the provincial part of the HST payable on meal expenses for long haul truck drivers will not be subject to recapture.

Special cases

Specified property and services brought into Ontario and British Columbia

If a large business:

- brings a specified property into Ontario or British Columbia from another province or country; or
- acquires a specified service in another province or country,

and the specified property or service is for use in Ontario or British Columbia (in whole or in part) by the large business, then that large business will generally be required to recapture the provincial component of the ITC that would have been available in respect of the specified property or service if the HST were payable in respect of that bringing in or acquisition (i.e., even if the property or service was acquired, or brought into the province, for consumption or use exclusively in commercial activities of the large business).

Example 33

A large business purchases an air conditioning unit in Quebec which it plans to install on a specified motor vehicle in Ontario. The acquisition and bringing into Ontario of the air conditioning unit is for exclusive use in the large business's commercial activities in Ontario. Because the air conditioning unit is a specified property, the large business will have to recapture the 8% provincial part of the HST for the ITC that is available, or would be available, if the provincial component of the HST were payable, on the air conditioning unit.

Expanded self-assessment rules will apply when tangible personal property is brought into a particular participating province from another participating province for which the provincial component of the HST is lower, and when intangible personal property or a service is acquired in a province for consumption, use or supply "significantly" (generally, 10% or more) in participating provinces for which the provincial component of the HST is higher than the provincial component of the HST for the province of acquisition. These proposed rules will be addressed in the GST/HST Technical Information Bulletin soon to be released, entitled *Harmonized Sales Tax – Self-Assessment of the Provincial Component of the HST*.

When a large business brings in tangible personal property that is specified property into Ontario or British Columbia from another participating province, an amount may be required to be recaptured. The amount is determined by the formula

A – B

where

"A" is the amount that would be such an input tax credit if

(a) a taxable supply (other than a zero-rated supply) of the tangible personal property were made in the province at that time,

(b) the consideration for the supply were equal to value, determined under the description of B in subsection 220.05(1) in respect of the tangible personal property at that time,

(c) the tangible personal property were not an item subject to the point of sale rebate for the provincial part of the HST in the province in which the tangible personal property was brought into, and

(d) tax in respect of the supply calculated on that consideration were paid by the person at that time; and

"B" is the amount if any, that is an input tax credit that is attributable to the provincial component of the HST under Division IV.1 of Part IX of the Act in respect of that bringing in.

Specified members of a qualifying group

If a large business is a specified member of a qualifying group that has made an election for closely related persons under the Act, and that large business acquires a specified property or service from another specified member of the same qualifying group, the large business will also generally be required to recapture the provincial component of any ITCs that would have been available if the HST were payable in respect of that acquisition (i.e., even if the supply is deemed under the Act to have been made for no consideration).

Example 34

Corporations A and B are both large businesses located in British Columbia and are also closely related persons that have made an election under the Act to have certain taxable supplies between them deemed to be made for no consideration. Corporation A sells a qualifying motor vehicle to Corporation B. Corporation B will be required to recapture the provincial component of any ITCs that would have been available if the HST were payable on the fair market value of that motor vehicle (i.e., even though that supply is deemed under the Act to have been made for no consideration.) Insofar as Corporation A purchased the motor vehicle for the sole purpose of re-supplying it to Corporation B, Corporation A will not be subject to the ITC recapture with respect to its original acquisition of the motor vehicle.

Non-arm's length transactions

If a supply of a specified property or service is made for no consideration, or for consideration at less than fair market value, between persons who are not dealing with each other at arm's length for purposes of the Act, the recipient of the supply (if it is a large business) will generally be required to recapture ITCs as if the supply had been made at fair market value (i.e., even if the property or service was acquired, or brought into the province, for consumption or use exclusively in commercial activities of the large business).

Example 35

Corporation X and Corporation Y, both located in Ontario, are not dealing with each other at arm's length. Corporation X sells a qualifying motor vehicle to Corporation Y, a large business, for $1. Even though Corporation Y plans to use the vehicle exclusively in the course of its commercial activities, it will be required to recapture the ITC on the provincial part of the HST, as if the vehicle had been purchased at fair market value.

Fuel acquired in or brought into British Columbia for use as specified energy

If a large business acquires or brings in fuel for use as specified energy in British Columbia, and that fuel was subject to the point of sale rebate in British Columbia, so that only 5% HST was paid or payable on the purchase, the large business will be required to recapture an amount equal to the provincial part of the HST that would have been payable.

Specified property or services supplied by the operator of a joint venture

Where an election under section 273 of the Act is in effect for a joint venture, paragraph 273(1)(c) of the Act deems supplies of property or services made by the operator to a co-venturer not to be supplies to the extent that the property or services are for consumption or use in the course of commercial activities for which the joint venture agreement was entered into.

If this property or service supplied to a co-venturer by the operator is a specified property or service, the co-venturer, if a large business, will be required to recapture an input tax credit equal to the provincial component of the HST that would have been payable if the supply of the property or service had not been deemed not to be a supply.

Allowances and reimbursements

If a large business pays an allowance or a reimbursement to an employee or a partner in circumstances where ITCs would be available under the Act to the large business in respect of that allowance or reimbursement, the large business will generally be required to recapture the provincial component of those ITCs to the extent that the allowance or reimbursement is attributable to specified property and services.

Example 36

A large business in Ontario reimburses an employee $113 (HST included) for meal expenses. The $13 ITC claimed by the large business with respect to this reimbursement is subject to the 50% recapture under section 236 of the Act. ($13 × 50% = $6.50). Since the meals are specified property, the large business will also be required to recapture the remaining $4 ITC in respect of the provincial portion of the HST on the reimbursement for these meal expenses ($6.50 × 8/13 = $4).

If a large business uses the factor method instead of the exact calculation method to compute the eligible input tax credits (ITCs) on reimbursements, these factors are 11/111 for reimbursements for taxable supplies made in British Columbia, and 12/112 for reimbursements for taxable supplies made in Ontario. For any of these reimbursements attributable to specified property or services, factors of 7/12 for British Columbia, and 8/13 for Ontario, may be used to determine the amount of the RITC.

Deduction from net tax – for qualifying motor vehicles sold or removed from the province

If, at a particular time, a large business sells a qualifying motor vehicle, or removes it from either the province of Ontario or British Columbia and registers it in another province, and the large business had previously reported an RITC in its net tax calculation for that motor vehicle, the person may deduct from its net tax for the reporting period that includes that time (that is, reduce the amount of RITC to report), an amount determined by the formula

$$A \times (B/C)$$

where

"A" is the total of all amounts reported as RITCs in respect of the last acquisition or bringing in of the qualifying motor vehicle by the large business

"B" is

(a) if the large business supplies the qualifying motor vehicle to a recipient that is not dealing at arm's length with the large business, or if the large business removes the qualifying motor vehicle from the province, the fair market value of the qualifying motor vehicle at that time, and

(b) in any other case, the consideration for the supply by way of sale of the qualifying motor vehicle; and

"C" is the consideration in respect of that last acquisition, or the value in respect of the last bringing in, of the qualifying motor vehicle by the large business in respect of which the amount determined under the description of A is attributable.

Example 37

In 2012, Large Business A (LBA) buys a qualifying motor vehicle for $40,000 for use in exclusively in its commercial activities. It pays $5,200 in HST and, since the vehicle is a passenger vehicle, claims ITCs of $3,900 ($30,000 × 13%) and reports $2,400 as an RITC ($30,000 × 8%). In June of 2015, LBA sells the vehicle for $10,000. It would deduct $800 ($2,400 × $10,000/$30,000) from the amount of RITCs it is required to report at that time.

Accounting for recaptured ITCs

When to account for recaptured ITCs

A large business will generally be required to account for recaptured ITCs in its GST/HST return for the reporting period in which the ITCs first become available, i.e., in the first reporting period in which the provincial component of the HST to which the ITCs relate becomes payable, or is paid without having become payable.

Example 38

A large business in British Columbia is engaged exclusively in commercial activities and is subject to RITCs. In September 2010, the large business pays $1,200 HST on the purchase of specified property. In its GST/HST return for the reporting period that includes the month of September, it is required to report $700 ($1,200 × 7/12, the provincial part of the HST) as an RITC.

Exception

If under the Act, a large business is currently required to recapture ITCs that it claimed in respect of a particular specified property or service in a reporting period other than the reporting period in which the ITCs first become available (i.e., certain meals and entertainment expenses and passenger vehicle lease payments), then the large business will generally be required, under the RITC requirement, to recapture the provincial part of the ITCs in respect of that same specified property or service in that same reporting period, , multiplied by the recapture rate(s) applicable to the reporting periods in which the HST became payable on the lease payments, The resulting amount would be the amount recaptured in that reporting period.

Example 39

A large business leases a passenger vehicle for $12,000 per year. The vehicle is a qualifying motor vehicle for use in Ontario. In its GST/HST returns throughout the taxation year, the large business claims $1,560 HST payable ($12,000 × 13%) on the lease payments as ITCs. Under section 235 of the Act, in the first reporting period following that year, the large business is required to recapture the ITCs claimed to the extent that the lease costs exceed the maximum lease costs allowed under the *Income Tax Act*. If the maximum lease cost allowed under that act is $9,600, then under section 235, the large business will be required to recapture $312 HST [($12,000 – $9,600)/$12,000 × $1,560]. In that same reporting period, the registrant would report $768 [($1,560 – $312) × 8/13], which is the remaining provincial component of the HST that had been claimed as an ITC, multiplied by the recapture rate(s) applicable to the reporting periods in which the HST became payable on the lease payments. The resulting amount will be the amount recaptured in that reporting period.

Administratively, the CRA allows GST/HST registrants to recapture the ITCs on passenger lease payments under section 235 of the Act and on meals and entertainment expenses under section 236 of the Act in the reporting period in which the tax became payable or was paid on these supplies. Registrants may also report the RITC on these lease payments, or on these meals and entertainment expenses, in that same reporting period.

Transitional measure

If a large business is the recipient of a supply of a specified property or service, and the consideration for the supply first becomes due, or is paid without having become due, after October 14, 2009 and before May 2010, then to the extent that

- the specified property is delivered, and ownership of the property is transferred to the large business, on or after July 1, 2010, or
- part of the specified service (at least 10%) is performed on or after July 1, 2010,

the large business will generally be required to self-assess the provincial component of the HST payable in respect of that property or part of the service either: (i) in the GST/HST return for the reporting period of the large business that includes July 1, 2010, if the due date for that return is before November 2010, or (ii) in any other case, in prescribed form and before November 2010. The large business will then recapture any ITCs available in respect of that provincial component of the HST in the GST/HST return for the reporting period in which any available ITCs first become available.

How to account for recaptured ITCs on the GST/HST NETFILE return

The CRA News Release and Backgrounder of January 4, 2010, entitled *Government of Canada announces new electronic filing requirements for GST/HST registrants*, announced that for reporting periods ending on or after July 1, 2010, GST/HST registrants who are subject to the RITC requirement (large businesses) will be required to calculate and report their ITCs in the GST/HST NETFILE return. GST/HST NETFILE is a free internet-based service that allows persons to file their returns with the CRA on-line.

The GST/HST NETFILE return will be similar to the existing GST/HST paper return, with some additional fields that will, among other things, allow filers to report recaptured ITCs. One of these new fields on the GST/HST NETFILE return will ask whether the filer is required to report recaptured ITCs in the reporting period. If the answer is yes, then a particular schedule to the return, *Schedule B, Calculation of Input Tax Credits* (Schedule B) will automatically be displayed and the filer will be required to complete that schedule in the following manner:

1. The filer will calculate the total amount of ITCs and adjustments claimed in that reporting period, including ITCs subject to recapture, and enter this amount in the field for Gross ITCs and Adjustments (before recapture).
2. The filer will calculate the total amount of ITCs subject to recapture in Ontario (Gross RITCs for Ontario) and, in a separate field, the total amount of ITCs subject to recapture in British Columbia (Gross RITCs for British Columbia).
3. Gross RITCs for Ontario and Gross RITCs for British Columbia will be multiplied by the rate of ITC recapture in effect in each province during the particular reporting period to arrive at Net RITCs for each province.
4. Net RITCs for each province will be added, and this sum will be automatically subtracted from Gross ITCs and Adjustments (before recapture) to arrive at Total ITCs and Adjustments for the purposes of calculating net tax.

The CRA has recently released a video on filing and paying your GST/HST return electronically. It can be viewed at http://www.cra-arc.gc.ca/gncy/hrmnztn/wbcsts/wtchwbcsts-eng.html?clp=wc20100326-06-eng. In addition, information on GST/HST NETFILE is available at http://www.cra-arc.gc.ca/esrvc-srvce/tx/bsnss/gsthst-tpstch-ntfl/menu-eng.html.

Example 40

In its September 2010 reporting period, a large business that is a monthly filer pays $2,000 in HST in the course of acquiring property, all of which is for use (and not resupply) in its commercial activities in Ontario. Of this amount, $1,300 is attributable to the acquisition of specified property by the large business (this $1,300 of HST is made up of a 5% federal portion of $500 and an 8% provincial portion of $800). The business does not acquire any specified property or services that are subject to ITC recapture in British Columbia.

In its GST/HST NETFILE return for the September reporting period, the large business indicates that it is required to recapture ITCs, and in Schedule B to the return:

- reports Gross ITCs and Adjustments (before recapture) of $2,000;
- reports $800 in the field for Gross RITCs in Ontario (and $0 in the field for Gross RITCs in British Columbia). This $800 will be automatically multiplied by the applicable recapture rate in Ontario (which will be 100% in September 2010) to arrive at Net RITCs of $800; and
- the $800 amount of Net RITCs is automatically subtracted from Gross ITCs and Adjustments ($2,000 – $800 = $1,200), and the difference is then auto-populated to the field for Total ITCs and Adjustments on Schedule B, and to line 108, Total ITCs and Adjustments of the GST/HST Return.

It is important to note that, other than the ITCs referred to in "Exception" in the section entitled "When to account for recaptured ITCs" and those referred to in "Use of qualifying motor vehicles before resupply" in the section entitled "Qualifying Motor Vehicles", a large business will be required to recapture the provincial portion of ITCs in respect of the provincial part of the tax paid or payable on specified property and services in the first reporting period in which the ITCs become available. Large businesses cannot simply forego claiming ITCs in order to fulfill the RITC requirement (even if the effect on net tax would be the same). In this way, the RITC requirement differs from the existing restriction on ITRs in Québec. Failing to recapture ITCs as and when required could result in penalties.

Example 41

Large Business A (LBA), which is a monthly filer, routinely acquires specified property in British Columbia. Rather than claim the ITCs for this property in the GST/HST return for the reporting period in which the ITCs first become available, LBA waits until the end of its fiscal year to claim the ITCs and to recapture the provincial portion of those ITCs. LBA will generally be subject to penalties in this situation because it should have recaptured the provincial portion of the ITCs in the reporting period when the ITCs first became available.

This approach to reporting and accounting for recaptured ITCs is necessary in order to allow administrators to properly allocate GST/HST revenues to HST provinces and to the federal government.

How to adjust GST/HST returns for misreported recaptured ITCs

If a large business incorrectly reports recaptured ITCs in a particular reporting period, and wishes to correct the error, it should send a letter to its local Tax Centre requesting that its GST/HST return for that period be adjusted to report the correct amount of recaptured ITCs. The Tax Centre will process the adjustment to the applicable reporting period.

Option to use an Estimation/Reconciliation Method for accounting of RITCs

In order to help simplify compliance with the RITC requirement, a large business may elect to use the Instalment Method (hereafter referred to as the Estimation/Reconciliation Method) to account for recaptured ITCs, using Form RC4531, *Election or Revocation of an Election to Use the Estimation and Reconciliation Method to Report the Recapture of Input Tax Credits*. A large business may file the election with the CRA in the following circumstances.

- If a GST/HST registrant exceeds the RITC threshold amount at the end of its fiscal year and becomes a large business on the first day of the next recapture period, (July 1), the election is effective on the first day of that recapture period and is to be filed on or before the due date of the GST/HST return for the reporting period that includes that month of July.
- If a GST/HST registrant that is a large business has been recapturing ITCs using the Actual Method and chooses to use the Estimation/Reconciliation Method, the election is effective the first day of the fourth month following the large business's fiscal year end. The election is to be filed on or before the due date of the GST/HST return for the reporting period that includes that day.

A GST/HST registrant cannot elect to use the Estimation/Reconciliation Method in a fiscal year, if that fiscal year is the registrant's first fiscal year.

An election to use the Estimation/Reconciliation Method remains in effect until revoked and can be revoked effective the first day of an instalment period that begins after the election became effective.

Under the Estimation/Reconciliation Method, for each province that has an RITC requirement, a large business will:

- estimate the amount of ITCs it will be required to recapture during a fiscal year;
- based on this estimate, report an equal amount of recaptured ITCs in each reporting period during the period that begins three months after the beginning of its fiscal year and ends three months after the end of that fiscal year (the Instalment Period); and
- at the end of its fiscal year, determine the actual amount of ITCs it should have recaptured during that fiscal year and reconcile any differences between the actual amount and the amounts reported during the fiscal year.

Under the Estimation/Reconciliation Method, a large business will still have to identify the specified property and services that it acquires or brings into a province in such a way that it could determine the actual amount of available ITCs that are subject to the RITC requirement in each province with such a requirement. However, this method will allow the large business to account for these recaptured ITCs on a fiscal year basis and on the basis of aggregate financial information.

Large businesses will still be able to use any proxies otherwise available to them when using the Estimation/Reconciliation Method (e.g. the proxy for specified energy used directly in the production of tangible personal property for sale).

Step 1: Estimation

At the beginning of a fiscal year, a large business that has filed the election with the CRA will make a reasonable estimate of the amount of ITCs that it will be required to recapture, for each province with an RITC requirement, during that fiscal year. This estimate of recaptured ITCs (Estimated RITCs) will be based on:

- ITCs that it would have been required to recapture during its most recently completed fiscal year if the RITC requirement had been in place throughout that year, and
- any additional ITCs that it would be required to recapture in its current fiscal year because of anticipated changes in circumstances (i.e., in comparison to the previous fiscal year).

A large business will not be allowed to use an Estimated RITC amount that was less than the actual amount of ITCs that the large business was (or would have been) required to recapture in the previous fiscal year. However, it could use a greater amount.

Example 42

Large Business A (LBA) has monthly reporting periods and a December 31 fiscal year end. It elects to use the Estimation/Reconciliation Method. Before July 1, 2010, LBA reviews its financial records and determines that ITCs subject to recapture for Ontario in its 2009 fiscal year would have been $6,000 if the RITC requirement had been in effect during that fiscal year.

Step 2: Reporting Estimated RITC amounts

A large business using the Estimation/Reconciliation Method will generally be required to report its Estimated RITC amount, for each province with an RITC requirement, over the course of the period that begins three months after the beginning of its fiscal year and ends three months after the end of that fiscal year (the Instalment Period).

The Estimation/Reconciliation Method is a simplification measure to ease the administrative burden of recapturing input tax credits for large businesses with substantial acquisitions of specified property and services. As a simplification measure, all specified property and services will be considered to be acquired evenly throughout a fiscal year. Therefore, to determine the amount of recaptured ITCs that must be reported in each reporting period during the Instalment Period, a large business will generally divide the relevant Estimated RITC amount by the number of GST/HST reporting periods in the Instalment Period (e.g., a monthly filer will generally divide the amount by 12). The equal amounts should be included in Schedule B to the GST/HST NETFILE return of the large business as Gross RITCs for each reporting period in the particular Instalment Period.

For 2010, the Instalment Period will generally be a 12 month period to calculate the monthly RITC amounts. However, the recapture period does not begin until July 1, 2010, so a large business will only begin reporting this monthly amount in the first reporting period that includes July 1, 2010.

Example 43

LBA, from example 42, has a December 31 fiscal year end. Its Instalment Period will run for the 12 monthly reporting periods from April to March each year. However, since the recapture period for 2010 begins July 1, 2010, LBA will only be required to report RITCs beginning in the reporting period that includes July 1, 2010.

LBA will report $500 ($6,000/12 reporting periods) as its estimated amount of Gross RITCs (ITCs subject to recapture) in each of its nine monthly reporting periods from July 1, 2010 to March 31, 2011, in the Instalment Period.

Step 3: Reconciliation

After the end of its fiscal year, a large business using the Estimation/Reconciliation Method will review its financial records and determine the actual amount of ITCs it would have been required to recapture, for each province with an RITC requirement, during that year. These amounts will represent the Actual RITCs for each of those provinces during that fiscal year.

The reconciliation will be completed in a reporting period of the large business that occurs within three months of the end of the fiscal year. For example, if a fiscal year ends on December 31 of a particular calendar year, the reconciliation should take place in a reporting period that includes a date before April 1 of the next calendar year.

However, to simplify administration, for RITC amounts reported in 2010, no reconciliation can take place before April 2011. If a large business has a fiscal year that ends after the implementation of the HST in July 2010 and before January 2011, it will be required to perform any relevant reconciliation in the reporting period that includes April 1, 2011. Similarly, if a large business has a fiscal year that ends after December 31, 2010, it will be required to perform any relevant reconciliation in a reporting period that includes a date that is on or after April 1, 2011, and is within three months of the end of its fiscal year.

Schedule C – Reconciliation of Recaptured Input Tax Credits (RITCs)

The GST/HST NETFILE return will be amended to include a question asking if a RITC reconciliation is being made for that reporting period. If the answer is yes, the registrant will be prompted to complete the reconciliation schedule. The large business will report the actual amount of input tax credits that should have been recaptured in the fiscal year. This amount will then be compared to the Gross RITCs amount reported to date in the Schedule B of the GST/HST returns for the same fiscal year using the Estimation/Reconciliation Method. The large business will report any differences between these two amounts in *Schecule C – Reconciliation of Recaptured Input Tax Credits (RITCs)* (Schedule C) of the GST/HST NETFILE return.

On Schedule C, the large business will also report the differences between the Actual Net RITCs that should have been reported, and the Net RITCs that were reported in the GST/HST returns for that fiscal year. The difference between these Net RITC amounts will be automatically recorded in a new field of the GST/HST NETFILE return. Until June 30, 2015, Net RITCs will be 100% of Gross RITCs. For Recapture Periods beginning July 1, 2015, and until June 30, 2018, Net RITCs will be a percentage of Gross RITCs.

Example 44

In March 2011, LBA (from examples 42 and 43) determines that, for its fiscal year ending December 31, 2010, its Actual RITCs from July 1, 2010 to December 31, 2010 are $3,200 and the Actual Net RITCs that should have been reported were $3,200 ($3,200 x 100% recapture rate). For the fiscal year ending December 31, 2010, LBA reported Net RITCs of $3,000. Therefore, LBA reports the Actual Net RITCs of $3,200 and the Net RITCs reported of $3,000 as well as the additional $200 of Net RITCs in its reconciliation schedule. The $200 difference in additional Net RITCs reported in the reconciliation schedule will be auto populated to the GST/HST NETFILE return as an addition to net tax.

Generally, LBA will report this additional $200 in the reconciliation schedule to its GST/HST NETFILE return in a reporting period that occurs within three months of the end of the fiscal year. However, to simplify administration, no reconciliation can take place before April 2011. LBA will report the additional $200 in the reconciliation schedule to its GST/HST NETFILE return for the April 2011 reporting period.

Estimating RITCs where the RITC requirement has been in effect less than one year

When using an amount of actual RITCs from a previous fiscal year as a basis for estimated RITCs for a current fiscal year, if in that previous fiscal year the RITC requirement was only in effect for part of that year, or the registrant becomes a large business for only part of that year, the large business will need to adjust that amount to reflect what its RITCs would be for the full fiscal year.

Example 45 – continued with LBA

In March 2011, LBA, from the previous example, had determined its Actual RITCs would have been $6,400 if the RITC requirement had been in effect for the full fiscal year. LBA also determines that an additional $2,000 of recaptured ITCs is expected in its fiscal year 2011 as a result of the anticipated acquisition of a new qualifying motor vehicle for use in the province.

Therefore, LBA's estimated RITCs for its fiscal year 2011 will be $8,400 ($6,400 + $2,000).

LBA will divide this estimated RITC amount by the 12 monthly reporting periods that occur in the Instalment Period starting April 1, 2011 and ending March 31, 2012.

LBA will report an amount of $700 ($8,400/12) in the Gross RITC field for the province in Schedule B of the GST/HST NETFILE return for each monthly reporting period that occurs in the Instalment Period from April 2011 through March 2012.

Reconciliation for the 2011 fiscal year, estimation, and reporting RITC amounts for the 2012 fiscal year

Example 46 – continued with LBA

In March 2012, LBA determines that, for its fiscal year ending December 31, 2011, its Actual RITCs were $9,000, and that its reported Gross RITCs (and Net RITCs) for that fiscal year were $7,800 {($500 × 3 months [Jan. to Mar. 2011]) + ($700 × 9 months [Apr. to Dec. 2011])}. LBA will report the Actual Net RITCs of $9,000 and the reported Net RITCs of $7,800 and the $1,200 difference in Schedule C of its GST/HST return for the March 2012 reporting period (i.e., in addition to the $700 Gross RITC amount reported in Schedule B for that reporting period).

LBA does not anticipate any material differences in its acquisition of specified property or services in its 2012 fiscal as compared to its 2011 fiscal year. Therefore, LBA will also use the $9,000 amount of Actual RITCs for the 2011 fiscal year as its Estimated RITC amount for its 2012 fiscal year. LBA reports $750 of Gross RITCs in each monthly reporting period contained in the Instalment Period from April 1, 2012 to March 31, 2013 (i.e., $9,000/12 reporting periods within the Instalment Period).

Estimation/Reconciliation Method – 2015 fiscal year

Example 47 – continued with LBA

In March 2015, based on its acquisition of specified property and services for its fiscal year ending December 31, 2014, LBA determines that its Actual RITCs for that fiscal year were $12,000. Since it does not anticipate any material differences in its acquisitions for its 2015 fiscal year, LBA will also use the Actual RITC amount of $12,000 for the 2014 fiscal year as its Gross Estimated RITCs for the Instalment period beginning in 2015. LBA therefore reports $1,000 of Gross RITCs in each monthly reporting period contained in the Instalment Period from April 1, 2015 to March 31, 2016 (i.e., $12,000/12 reporting periods within the Instalment Period). (Assume that for the monthly reporting periods of January to March 2015, LBA is reporting Gross RITCs of $900 from the Instalment Period of April 1, 2014 to March 31, 2015, based on Actual RITCs of $10,800 for the 2013 fiscal year.)

However, beginning in July 2015, the recapture rate for the Recapture Period, July 1, 2015 to June 30, 2016, will be 75%, instead of 100%. From July 1, 2015, the amounts recorded in the Gross RITCs line of Schedule B will be multiplied by the RITC rate of 75%, so that the Net RITCs for each reporting period in the Instalment Period from that date will be $750 ($1,000 × 75%).

In Schedule B of its GST/HST NETFILE returns for the fiscal year ending December 31, 2015, LBA will report: Gross RITCs of $11,700 {($900 × 3 reporting periods [Jan. to March 2015]) + ($1,000 × 9 reporting periods [April to Dec. 2015])} and Net RITCs of $10,200 {($900 × 100% × 3 reporting periods [Jan. to March 2015]) + ($1,000 × 100% × 3 reporting periods [April to June 2015]) + ($1,000 × 75% × 6 reporting periods [July 2015 to Dec. 2015])}.

In March 2016, LBA reviews its 2015 fiscal year, and determines that its Actual RITCs for that fiscal year were **$**15,000**.** However, since the recapture rate changed to 75% on July 1, 2015, LBA determines that its Net RITCs are $13,125 for its 2015 fiscal year {($1,250 × 100% × 6 reporting periods [Jan. to June 2015]) + ($1,250 × 75% × 6 reporting periods [July to Dec. 2015])}.

LBA reports the Actual Net RITCs of $13,125 and the Net RITCs reported of $10,200 and the $2,925 ($13,125 – $10,200) difference in the Reconciliation Schedule for the March 2016 reporting period. The $2,925 difference in Net RITCs will be transferred to a field on the GST/HST return as an addition to net tax.

2016 fiscal year

Example 48 – continued with LBA

LBA will use the $15,000 amount of input tax credits subject to recapture from its 2015 fiscal year to estimate its Gross RITCs for the Instalment Period of April 1, 2016 to March 31, 2017. In July 2016, the RITC recapture rate for that Recapture Period ending June 30, 2017 will be reduced to 50% from 75%.

In Schedule B to its GST/HST NETFILE returns for the fiscal year ending December 31, 2016, LBA will report Gross RITCs of $14,250 {($1,000 × 3 reporting periods [Jan. to Mar. 2016]) + ($1,250 × 9 reporting periods [Apr. to Dec. 2016])} and Net RITCs of $8,813 {($1,000 × 75% × 3 reporting periods [Jan. to Mar. 2016]) + ($1250 × 75% for 3 reporting periods (Apr. to June 2016]) + ($1,250 × 50% x 6 reporting periods [July to Dec. 2016])}.

In March 2017, LBA reviews its December 31, 2016 fiscal year, and determines that its Actual input tax credits subject to recapture for that fiscal year were $16,500, or $1,375 per month ($16,500/12). However, since the recapture rate changed to 50% on July 1, 2016, LBA determines that its Net RITCs should have been $10,313 for its 2016 fiscal year {($1,375 × 75% × 6 reporting periods [Jan. to June 2016]) + ($1,375 × 50% × 6 reporting periods [July to Dec. 2016])}.

In the Reconciliation Schedule for the March 2017 reporting period, LBA reports the $10,313 of Actual Net RITCs for the 2016 fiscal year, the $8,813 of Reported Net RITCs for that year, and the $1,500 difference ($10,313 – $8,813) in Net RITCs. The $1,500 difference in Net RITCs will be transferred to a field on the GST/HST return as an addition to net tax.

The last recapture period ending June 30, 2018

Example 49 – continued with LBA

In March 2018, LBA reviewed its financial records and determined that its Actual RITCs for its fiscal year ending December 31, 2017 were $18,000. Since it does not anticipate any major change in business activity, it uses $18,000 as its base for its Estimated RITCs for the 2018 fiscal year, and will report $1,500 ($18,000/12 months) as Gross RITCs for each reporting period beginning April 2018. (For each of the January to March 2018 reporting periods, LBA has continued to report Gross RITCs of $1,375 from the Instalment Period of April 2017 to March 2018.) Since the requirement to report RITCs ends June 30, 2018, LBA reports $8,625 of Gross RITCs for Ontario in the six reporting periods ending June 30 {($1,375 × 3 reporting periods [Jan. to March 2018]) + ($1,500 × 3 reporting periods [April to June 2018])} and Net RITCs of $2,156 {($1,375 × 25% × 3 reporting periods [Jan. to March 2018]) + ($1,500 × 25% × 3 reporting periods [April to June 2018])}.

In March 2019, LBA determines that its Actual RITCs for the December 31, 2018 fiscal year end would have been $18,000 if the RITC recapture requirements had been in effect all year. It calculates its Actual RITCs that it will be required to recapture as $9,000 ($18,000/12 × 6 months) since the recapture period ended June 30, 2018. Its Net RITCs for that fiscal year will be $2,250 ($9,000 × 25% [Jan. to June 2018]). In its reconciliation schedule of its GST/HST NETFILE return for the March 2019 reporting period, LBA will report the $2,250 Actual Net RITCs for the 2018 fiscal year, the $2,156 Net RITCs that were reported in that fiscal year, and the $94 difference in the Net RITCs ($2,250 – $2,156). The $94 difference in Net RITCs will be transferred to a field on the GST/HST return as an addition to net tax.

Estimation/Reconciliation Method – special cases

Large business at the time of GST/HST registration

If a person is a large business at the time it registers for GST/HST (for example, because the RITC thresholds of its associated persons are over $10 million), the large business cannot elect to use the Estimation/Reconciliation Method for reporting its RITCs, if this is the large business's first fiscal year. However, it may elect to use the Estimation/Reconciliation Method for reporting its RITCs in its GST/HST returns in its first Instalment Period in its next fiscal year. The large business would estimate its RITCs based on its current fiscal year.

Example 50

A corporation begins business on June 1, 2012, and registers for GST/HST at that time. Due to the RITC threshold of its associates, the corporation is a large business at the time of registration. However, since this is the corporation's first fiscal year, the corporation may file the election to use the Estimation/Reconciliation Method to determine its RITCs in its next fiscal year, beginning April 1, 2013, the beginning of the next Instalment Period. It will estimate its RITCs for that Instalment Period based on the Actual RITCs for its fiscal year ending December 31, 2012, adjusted to reflect a full fiscal year.

Estimated RITCs based on a prior short fiscal year

Where a large business's Estimated RITCs are based on a prior fiscal year that is shorter than one year, the large business will need to prorate the RITCs from the prior fiscal year to reflect a one year period.

Example 51

From the previous example, the corporation's fiscal year ending December 31, 2012, is seven months long. Its Actual RITCs for that year are $7,000. To estimate its RITCs for the Instalment Period of April 1, 2013 to March 31, 2014, it prorates this amount and anticipates that its RITCs are $12,000 for that Instalment Period. Therefore it will report $1,000 as Gross RITCs in each reporting period of its Instalment Period of April 2013 to March 2014.

When a large business ceases to be registered for GST/HST purposes

If a large business ceases to be registered for GST/HST purposes (for example, the legal entity no longer exists because it is wound up or it amalgamates with another corporation) then its Instalment Period will also end on that date. It will be required to reconcile its RITCs in its GST/HST NETFILE return for its last reporting period that it is registered for GST/HST.

Example 52

On September 15, 2012, a large business, that has elected to use the Estimation/Reconciliation Method for accounting for RITCs, is wound up into its parent company. The large business has a December 31 fiscal year end, and therefore its Instalment Period normally runs from April to March each year. However, since it ceases to exist as of September 15, 2012, its Instalment Period will end that date.

The large business will need to complete its reconciliation schedule by the due date of its GST/HST NETFILE return for its last reporting period that it is registered for GST/HST.

Enquiries by telephone

Technical enquiries on the GST/HST: 1-800-959-8287

General enquiries on the GST/HST: 1-800-959-5525 (Business Enquiries)

If you are located in Quebec: 1-800-567-4692 (Revenu Québec)

All technical publications related to the GST/HST are available on the CRA Web site at www.cra.gc.ca/gsthsttech.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 2, Page 2

Please explain what "short-term exchange service revenue" is. Please provide details and examples.

Response:

Short-term exchange service revenue is the revenue from Union's exchange service which allows shippers to receive/deliver gas from one point on Union's system and receive/deliver an equal quantity of gas to an off system point of an upstream or downstream pipeline.

An example of an exchange service is Customer A delivers gas to Union at Dawn and Union delivers the same amount of gas to Customer A on that same day at Enbridge CDA.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 3, Page 2

Unabsorbed Demand Cost Variance Account.

Please explain in detail how UDC arises in Union North. Why is UDC allocated to both sales gas customers and direct purchase customers?

Response:

Union continues to hold capacity on Trans-Canada Pipelines and Michcon/Great Lakes Gas Transmission in excess of that required to meet normal weather loads in order to serve peak day firm loads for sales service and bundled-T customers in Union North.

UDC costs in Union North are allocated to sales service and bundled direct purchase customers as Union incurs UDC in the provision of transportation service to both groups of customers.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 3, Page 5

Please provide a breakdown of the 2011 DSM spent between June 1, 2011 and December 31, 2011.

Response:

2011 DSM Actual Spend [(1)]		
Jan	$	535,636
Feb	$	2,399,124
Mar	$	1,136,836
Apr	$	1,930,852
May	$	1,512,052
Jun	$	1,793,809
Jul	$	2,043,045
Aug	$	1,913,018
Sep	$	2,046,425
Oct	$	1,492,609
Nov	$	3,115,917
Dec	$	5,995,540
Total	$	25,914,863

Notes:
(1) Excludes incremental Low-income and includes indirect costs.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 3, Page 6, Line 13

Allocation of HST Related Operations and Maintenance Savings.

Why is the cost of gas excluded from O&M costs in this calculation?

Response:

The cost of gas related balances in the Harmonized Sales Tax deferral (179-124) are included in the Compressor Fuel Costs portion of the deferral account.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 3, Page 7

Please show the difference in allocation by rate class of the low-income incentive if it were allocated across all claims based on DSM spent.

Response:

Please see Attachment 1.

UNION GAS LIMITED
Allocation of Low-Income Incentive Amounts
2011 Net Volume Savings vs. 2011 Actual DSM Costs

Rate Class	2011 Net Volume Savings (m^3) (a)	Allocation of Low-Income Incentive ($000's) (b) = based on (a)	2011 Actual DSM Costs ($000's) (c)	Allocation of Low-Income Incentive ($000's) (d) = based on (c)	Variance ($000's) (e) = (d - b)
Rate 01	75,133	79	2,568	53	(26)
Rate 10	-	-	846	18	18
Rate 20	-	-	573	12	12
Rate 100	-	-	834	17	17
Rate M1	439,366	465	10,106	209	(256)
Rate M2	-	-	3,300	68	68
Rate M4	-	-	987	20	20
Rate M5A	-	-	2,104	44	44
Rate M7	-	-	588	12	12
Rate T1	-	-	4,364	90	90
Total	**514,499**	**544**	**26,271**	**544**	-

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 4, Page 4

a) Is the 21,101 GJ/d of firm supply delivered to Dawn via MichCon, a part of the 25,000 firm capacity on Panhandle, or is it 20,000 btus additional to 25,000 btus to Ojibway? If yes, what is the estimated UDC on unused portion of the Panhandle capacity from the Panhandle/MichCon interconnect to Ojibway? Please provide details and a diagram.

b) Why is all the gas from the Panhandle Field Zone not routed through Ojibway to Dawn?

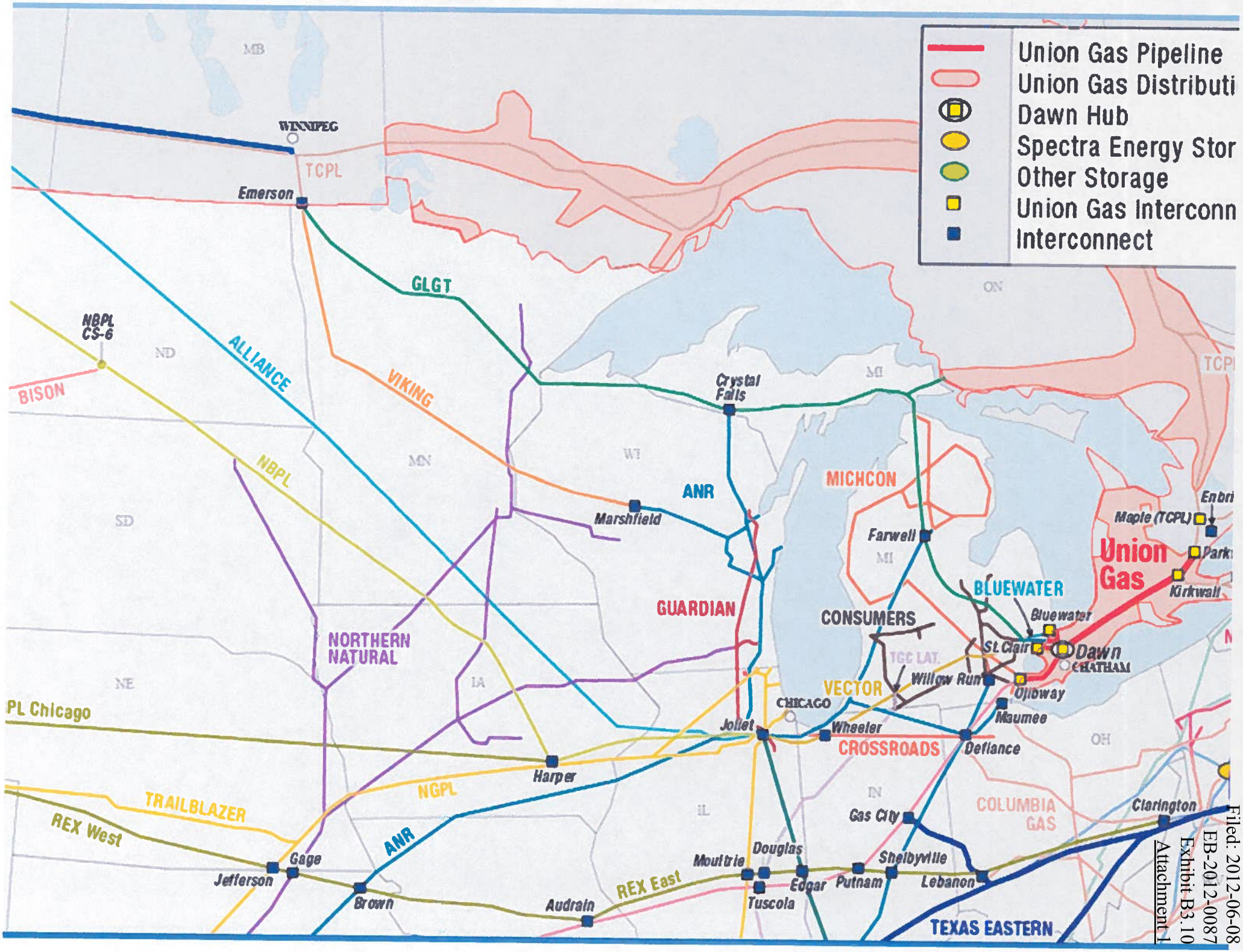
c) Please explain the meaning of "Exchange Service" at page 7.

Response:

a) The two references refer two distinct transportation paths. The capacity described starting on line 10 of Exhibit A, Tab 4, Page 4, is an existing Panhandle path that Union holds in its portfolio (Panhandle to Ojibway path with a capacity of 25,000 mmbtu/d). The capacity described starting on line 14 of Exhibit A, Tab 4, Page 4 is the capacity that is new to Union's portfolio as of November 1, 2011 (Panhandle to MichCon path with a capacity of 20,000 mmbtu/d). There is no estimated UDC on either transportation path. Please see Attachment 1 for a diagram of the referenced pipes along with the other major pipelines in the area.

b) At the time of the acquisition of the asset, the Panhandle Ojibway delivery point was fully contracted and unavailable to Union.

c) An exchange service is a transportation service that allows a Shipper to deliver gas in one location and receive it back at another.



UNION GAS LIMITED

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

Ref: Exhibit A, Tab 4, Page 10

TransCanada Pipelines Contract

Is the arrangement described on pages 11 to 12 a backhaul arrangement? Please explain fully.

Response:

No. According to the TransCanada website, to qualify as Firm Backhaul Transportation (FBT), "The service requested must be against the flow of gas on TransCanada's Canadian Mainline System over the entire path for the entire year in which service is provided."[1]
The Service contract parameter on line 14 of Exhibit A, Tab 4, Page 12, indicates that the service is Firm Gas Transportation (FT) which is forward haul.

[1] *Source: http://www.transcanada.com/customerexpress/2843.html.*

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Page 13

The evidence states that the incremental Low-income budget of $2.465 million for 2011 was not included in rates so the entire amount is included in rates through the DSMVA. Table 2 indicates that the budget for Low-income DSM was $1.9 million and the actual spend was $1.729 million. Please reconcile these numbers.

Response:

The incremental Low-income budget of $2.465 million was approved by the Board in EB-2010-0055 on December 20, 2010 and is incremental to the $1.903 million budget for Low-income programs under the multi-year DSM framework established in the EB-2006-0021.

The Low-income budget shown on line 2 of Table 2 is the budget allocated to deliver the Helping Homes Conserve program which provides showerheads, aerators and programmable thermostats to qualifying Low-income participants. The incremental Low-income budget shown on line 8 is incremental to Union's 2011 DSM budget and is recovered solely through the 2011 DSMVA. The incremental Low-income spend of $2.056 million was utilized for the Low-Income Home Weatherization program and contributed 514,599 m^3 of savings in 450 qualified Low-income homes.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Page 14

Please confirm that all 2011 and 2012 GDAR costs will be subject to a prudence review as part of Union's 2012 Earnings Sharing and Deferral Account Disposition proceeding.

Response:

Confirmed.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Page 20

For all amounts in Account 179-123 Conservation and Demand Management please provide detailed calculations to support the revenue numbers. Please set out all program costs and related revenues for each of the initiatives Union undertook.

Response:

Please see the response at Exhibit B1.6 a).

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 2, Page 2

The evidence indicates that in 2011 there was an increase in operating expenses of $19.5 million relative to 2010. Please provide a schedule setting out all items included in the $19.5 million and all supporting calculations. Please provide a detailed schedule setting out 2011 actual O&M and 2007 Board approved O&M.

Response:

Particulars ($ Millions)	Actual 2010 [(1)]	Actual 2011[(2)]	Difference
Operating and maintenance expenses	349.4	369.5	20.1
Depreciation	190.2	195.5	5.3
Other financing	0.6	0.3	(0.3)
Property and capital taxes	65.1	60.7	(4.4)
Loss/(Gain) on foreign exchange	0.5	(0.7)	(1.2)
Total Expenses	605.8	625.3	19.5

Notes:
(1) Exhibit A, Tab 2, Appendix B, Schedule 1.
(2) EB-2012-0087, Exhibit A, Tab 2, Appendix B, Schedule 1.

Exhibit A, Tab 2, Appendix A, Schedule 13 sets out the 2011 actual O&M and the 2007 Board-approved O&M.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 2, Page 9

Please provide a schedule setting out each of the individual items that have contributed to the $11.948 million of over-earnings.

Response:

Please see Attachment 1.

UNION GAS LIMITED
Revenue Sufficiency Components

Line. No.	Particulars ($ millions)	2007 BA vs 2011
		(a)
	Revenue:	
1	Contract Market	3
2	General Service Market	17
3	S&T[(1)]	45
4	Other Revenue	(1)
5	Sub Total: Net Revenue	64
6	Delivery-related Gas Costs:	46
	O&M:	
7	Compensation	(57)
8	Contract Services	(15)
9	DSM Programs	(5)
10	Outbound Affiliates	6
11	Bad Debt	7
12	Capitalization	9
13	Non-Utility Allocations	7
14	Other	2
15	Sub Total: Net O&M	(46)
16	Other Expense	1
17	Rate Base Growth Net of Tax Changes & Debt Costs	(11)
18	ROE Formula Change	8
19	Revenue Sufficiency	62

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

Reconciliation of Revenue Sufficiency to Earnings Sharing

Line No.	Particulars ($ millions)	2011 Utility
20	Pre-tax revenue sufficiency	62
21	After-tax revenue sufficiency	45
22	Common equity	1,290
23	Revenue sufficiency return on equity (line 21 / line 22)	3.47%
24	Revenue sufficiency benchmark return on equity	2.00%
25	50% Earnings sharing % (line 23 - line 24, maximum 1%)	1.00%
26	90% Earnings sharing to ratepayer % (if line 25 = 1% then line 23 - line 24 - line 25)	0.47%
27	50% Earnings sharing $ (line 22 x line 25 x 50%)	6
28	90% Earnings sharing to ratepayer $ (line 22 x line 26 x 90%)	6
29	Total earnings sharing $ (line 27 + line 28)	12

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Pages 2-4

Please explain why UDC collected in the North of $6.217M is less than the amount of planned UDC in the North of $6.489M, whereas UDC collected in the South of $0.146M exceeds planned UDC in the South of $0.117M.

Response:

The difference between UDC amounts included in 2011 Board-approved rates compared to UDC amounts collected in rates is related solely to the difference between forecast and actual volumes.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Pages 2-4

Please explain how "UDC Costs Incurred" of $0.525M for Union North are derived.

Response:

The costs reflected in the UDC deferral account are the demand charges for unfilled capacity offset by revenue generated from transportation releases. As indicated at Exhibit B3.1, unfilled capacity was sold on the secondary market to minimize UDC. Revenues generated from the transportation releases were credited to the UDC deferral account mitigating the UDC impact.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Pages 4-6
Exhibit A, Tab 1, Schedule 7

Please confirm that the calculation of the debit balance recoverable from ratepayers, using the amount embedded in rates of $11.254M as advocated by CME and others in the Review Proceeding that the Board is conducting in EB-2012-0206, is $4.145M derived as follows:

Actual 2011 Net Margins	$7.899M
Less 10% Incentive to Union	$0.790M
90% of actual revenues	$7.109M
Less amount embedded in rates	$11.254M
Debit balance charged to ratepayers	($4.145M)
Debit claimed by Union	($7.137M)
Difference	$2.992M

(Being the same $2.992M amount in issue in the Review Proceeding)

Response:

Please see the response at Exhibit B1.1 a).

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Pages 18
Exhibit A, Tab 1, Schedule 5

The evidence indicates that, after normalizing for weather, Actual 2011 Average Uses for the customer classes shown in Exhibit A, Tab 1, Schedule 5 were higher than they were in 2010. In connection with this evidence, please provide the following information:

a) Please explain why 2011 Normalized Average Uses increased over 2010 Normalized Average Uses.

b) Please provide Actual Average Uses for the customer classes shown in Exhibit A, Tab 1, Schedule 5 at line 4 before normalizing for weather.

Response:

a) The key contributor to the increase in average use per customer in 2011 was usage in the commercial and industrial service classes.

The commercial market experienced a sharp increase in weather normalized average consumption per customer throughout the franchise in 2011. Consumption data for the first four months of 2012 indicate that this observed high usage level and increase for 2011 is receding. The first four months of the year represent about half of annual usage. About half of the spike seen in 2011 usage has vanished.

In the industrial market, total weather normalized volumes in 2011 fell from 2010. The total number of billed customers also declined over the two years. Average use rose between 2010 and 2011. This indicates that the customer loss was principally small usage customers which caused the average of all industrial customers to increase.

For the residential customers in aggregate the usage fell between 2010 and 2011. In the southern franchise residential usage fell while in the northern franchise it rose.

b) The table below provides the recorded actual average consumption per customer for 2010 and 2011 by rate class. The usage levels tabled below are not weather normalized and are not adjusted for the DSM saved volumes. The year 2010 was 6.5% warmer than normal in the southern franchise and 12.3% warmer in the north. The year 2011 was 3.3% warmer than normal in the southern franchise and 6.9% warmer in the north. The AU deferral account

weather normalizes on the basis of the 2007 weather normal.

Actual Annual Use per Customer: m3

Rate Class	2010	2011
Former Rate M2	3,729	3,912
Rate 01	2,737	2,921
Rate 10	145,575	159,621

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, Page 20
Exhibit A, Tab 1, Schedule 1, lines 15 and 16

The evidence indicates that Union was authorized to close Deferral Accounts 179-121 and 1779-122 effective April 1 ,2 012. Please revise Exhibit A, Tab 1, Schedule 1 to include the credit balances in the St. Clair Line Deferral Accounts at lines 15 and 16 of Exhibit A, Tab 1, Schedule 1 as they were at December 31, 2011, and provide a revised Exhibit A, Tab 1, Schedule 1 showing a debit balance at line 2 of $4.145M, rather than $7.137M, along with the credit balances at lines 15 and 16 as requested herein, and a revised total at line 23.

Response:

Exhibit A, Tab 1, Schedule 1 refers to the Deferral Account balances Union is requesting disposition of.

In May 2011, the Ontario Energy Board released its decision finding that deferral accounts will only be disposed of to ratepayers if the sale of the St. Clair Line is completed, on or before December 31, 2011.

In December 2011, the sale of the St. Clair Line was cancelled and deferral accounts 179-121 and 179-122 were taken into income. As a result at December 31, 2011, there were no longer balances in these accounts to dispose of to ratepayers.

Exhibit A, Tab 1, Schedule 1 will be revised if applicable based upon approval of final balances for all 2011 deferral accounts and an order for final disposition of those balances.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Pages 1-9
Exhibit A, Tab 2, Appendix A, Schedule 3
Exhibit A, Tab 2, Appendix B, Schedule 1

In column (k) of Exhibit A, Tab 2, Appendix A, Schedule 3, Union reduces "Earnings Before Interest and Taxes" by amounts relating to the removal of the St. Clair Transmission Line from rates in 2011. However, in Exhibit A, Tab 1, Schedule 1, Union has excluded the December 31, 2011 credit balances in the St. Clair Line Deferral Accounts at lines 15 and 16. Please provide a revised Exhibit A, Tab 2, Appendix A, Schedule 3 to eliminate from column (k) all of the adjustments pertaining to the "Impact of removing the St. Clair Transmission Line from Rates" and provide a revised Exhibit A, Tab 2, Appendix B, Schedule 1 to show the calculation of the Earnings Sharing amount at line 35 to reflect the adjustments requested herein.

We calculate that the Earnings Sharing amount increases from $16.652M to $20.150M and are seeking to ascertain whether our revised calculation is correct.

Response:

In 2011, the St. Clair pipeline asset is not included in the utility rate base, therefore, the return on rate base, depreciation, income taxes have not been included in the earnings sharing calculation. The revenue adjustment of $2.220 million represents the revenue requirement on these assets for 22 months, designed to achieve a regulated rate of return on rate base.

It's not appropriate to include the revenue in the 2011 earnings sharing calculation without also including the associated interest and taxes. Since the result is by design to achieve regulated rate of return there will be no impact on the earnings sharing calculation.

Union did, however, include the revenue from third party shippers using the St. Clair Line in the calculation of utility earnings.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 3, Pages 1-9
Exhibit A, Tab 3, Schedule 1, Page 1

What percentage increases in delivery rates will Union's M2, M5A, M7 and T1 customers face if the total amounts shown at line 27 of Exhibit A, Tab 3, Schedule 1, page 1 for each of those rate classes are found by the Board to be recoverable?

Response:

The total proposed amount for disposition (prospective or one-time adjustment) for Rate M2, Rate M5A, Rate M7 and Rate T1 relative to 2011 Board-approved delivery and storage revenue is provided in Attachment 1.

2011 Proposed Amounts for Disposal as a Relative Percentage of
2011 Board-approved Delivery and Storage Revenue

Line No.	Particulars	EB-2010-0148 Board-approved Delivery & Storage Revenue (1) ($000's)	EB-2012-0087 Proposed Amount for Disposal (2) ($000's)	Percent of Annual Revenue (%)
		(a)	(b)	(c) = (b / a)
1	Rate M2	48,957	902	1.8
2	Rate M5A	7,210	4,397	61.0
3	Rate M7	6,341	659	10.4
4	Rate T1	55,048	9,640	17.5

Notes:
(1) EB-2010-0148, Rate Order, Working Papers, Schedule 3, page 2, column (q).
(2) Exhibit A, Tab 3, Schedule 1, page 1, line 27, excluding UDC amounts in line 1 which are disposed of in the commodity price adjustment.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 4, Pages 13-15
Exhibit A, Tab 4, Schedule 3

Please list each of the items of expense increase risk that Union faces in 2012 and provide an estimate of its total increased expense exposure in the event that the Board declines to consider the changes that Union proposes to this Deferral Account in this proceeding and defers all matters relating to the proposed change in the scope of this Deferral Account to Union's 2013 Rebasing case.

Response:

In 2012, Union has a non-TCPL transportation contract serving the North that commenced November 2011 at lower tolls than TCPL. To ensure that the ratepayers receive the benefit of these lower tolls Union is deferring the variance to be refunded to ratepayers. The changes in the deferral account wording are intended to reflect the reality of the current portfolio and potential for transportation paths other than TCPL to serve Union's North customers.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit A, Page 3 &
Exhibit A, Tab 1, Schedule 7

a) Please provide the calculation of the O&M (line 5) based on 7,9 PJs of excess in-franchise storage capacity.

b) Please discuss why the O&M amount hasn't changed 2010-2011.

c) Please provide transaction history 2007-2011.

d) Please provide the amount embedded in rates.

e) If this differs from that shown, then please revise Schedule 7 accordingly.

Response:

a) Please see Attachment 1.

b) Please see the response at Exhibit B1.1 b).

c) Please see Attachment 2.

d) As shown at EB-2010-0148, Rate Order, Working Papers, Schedule 14, line 7, column (h), the total Short-Term Storage & Balancing Services Margin included in 2011 In-franchise rates is $11.254 million.

e) Please see the response at Exhibit B1.1 a).

UNION GAS LIMITED

Calculation of Demand Related Costs of the Excess Utility Storage Space

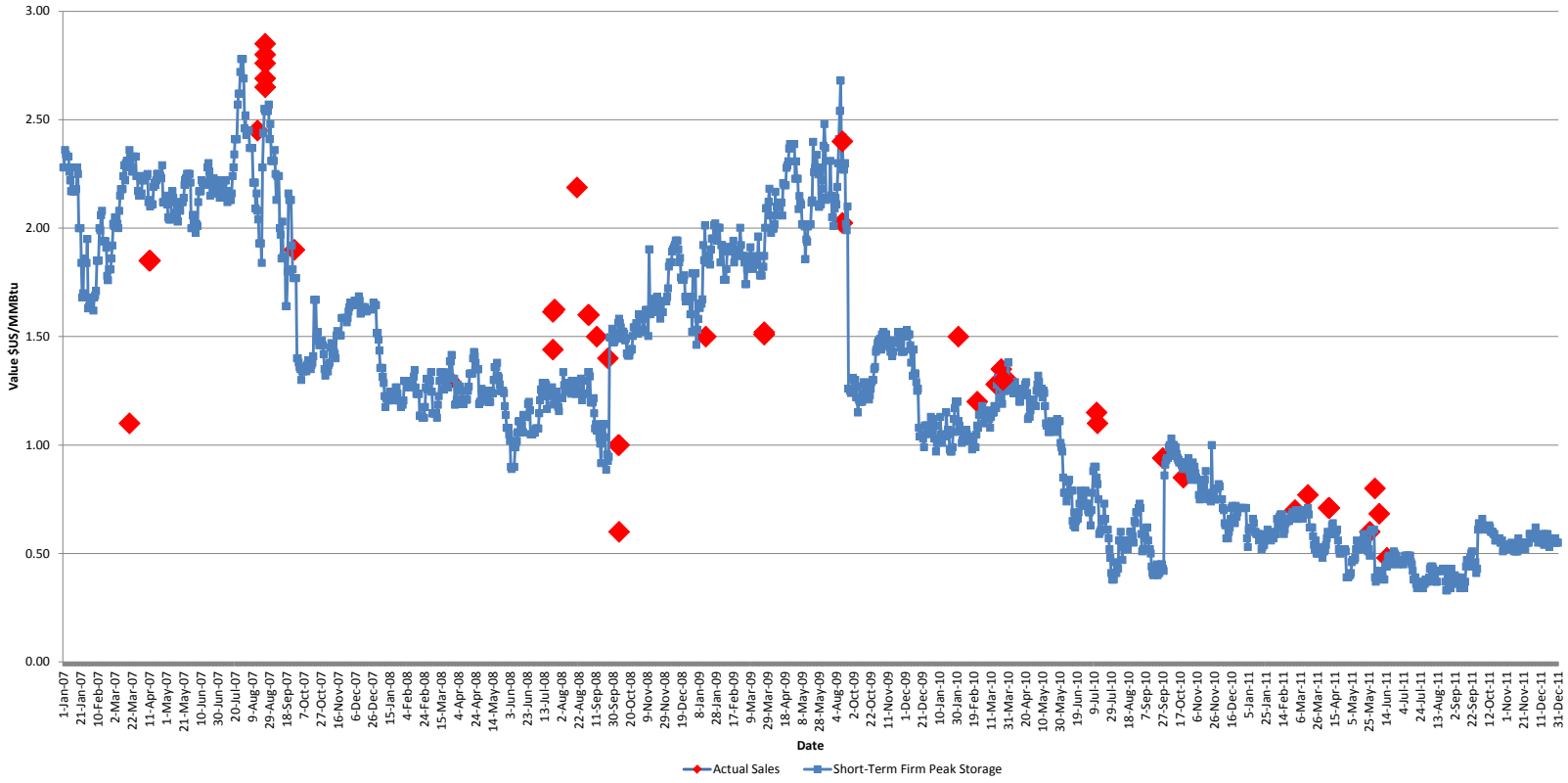
Line No.	Particulars (000's)	Board-Approved 2007 Cost Study C1-Storage [1]	Adjusted Board-Approved 2007 Cost Study C1-Storage [2]	Difference
		(a)	(b)	(a - b = c)
1	Depreciation	4,722	4,224	498
2	Return on Rate Base	8,433	7,528	905
3	Property, Capital & Income Taxes	2,143	1,915	228
4	Deferred tax drawdown	(1,065)	(952)	(113)
5	Operating and Maintenance Expenses [3]	7,002	6,259	743
6	Totals	21,235	18,974	
7	Demand Related Costs of the Excess Utility Storage Space			2,261

(1) EB-2005-0520, Exhibit G3, Tab 5, Schedule 1 with updates from EB-2005-0520, Settlement Agreement, Appendix E.

(2) 2007 Board-approved Cost of Service EB-2005-0520 C1-Storage adjusted for the regulated excess in-franchise storage space of 7.9 PJs.

(3) 2007 Board-approved operating and maintenance expense less cost of gas and compressor fuel.

Figure 2
Historical Short -Term Firm Peak Storage Values and Actual Sales Values at Dawn
2007-2011



UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit A, Tab 1, Schedule 4 &
Exhibit A, Tab 3, Schedule 4

a) Please provide the working papers/calculations supporting the amounts in column d 2011 unaudited results per EB-2006-0021.

b) In the second reference please indicate if the 2011 SSM allocation will be based on TRC or Spend. Please provide details.

c) Provide a summary of the rules governing Budget, Spend and reallocation of budgets among classes.

Response:

a) Please see Attachment 1 for the calculation of the total 2011 amount of $9,243,367, based on unaudited results as found in column d) of Exhibit A Tab 1, Schedule 4. Also included is a detailed listing of all the projects by rate class that underpin the calculation of SSM.

b) The SSM allocation for 2011 is based on TRC. The table below provides details of the TRC by rate class and the corresponding SSM allocation.

Rate	Total TRC	% of Total TRC	% of total TRC times SSM Incentive
M1 South Residential	$ 24,029,306	6.18%	$ 570,854
M1 South Commercial	$ 10,199,020	2.62%	$ 242,294
M1 South Industrial	$ 3,091,332	0.79%	$ 73,439
M2 South Commercial	$ 12,238,504	3.15%	$ 290,745
M2 South Industrial	$ 8,722,226	2.24%	$ 207,210
M4 South Industrial	$ 21,582,100	5.55%	$ 512,717
M5 South Industrial	$ 41,269,357	10.61%	$ 980,419
M7 South Industrial	$ 25,692,251	6.60%	$ 610,360
T1 South Industrial	$ 185,284,729	47.62%	$ 4,401,731
01 North Residential	$ 7,644,914	1.96%	$ 181,617
01 North Commercial	$ 2,993,003	0.77%	$ 71,104
10 North Commercial	$ 3,335,996	0.86%	$ 79,252
10 North Industrial	$ 1,054,202	0.27%	$ 25,044
20 North Industrial	$ 12,264,393	3.15%	$ 291,360
100 North Industrial	$ 29,685,298	7.63%	$ 705,221
Total	**$ 389,086,629**	**100%**	**$ 9,243,367**

c) Union's 2011 DSM plan (EB-2010-0055) approved by the Board on September 9, 2010 determined that the DSM budget for 2011would be $24.890 million. The budget represents the 2010 budget of $22.627 million increased by 10%.

Please see the response at Exhibit B2.3.

SSM incentive is calculated using the following structure:

• For TRC savings between 0 percent and 25 percent of the TRC target, an SSM payout shall equal $900 for each 1/10 of 1 percent of target reached;
• For TRC savings between 25 percent and 50 percent of the TRC target, an SSM payout shall equal $225,000 plus $1,800 for each 1/10 of 1 percent of target reached;
• For TRC savings between 50 percent and 75 percent of the TRC target, an SSM payout shall equal $675,000 plus $6,300 for each 1/10 of 1 percent of target reached; and,
• For TRC savings greater than 75 percent of the TRC target, an SSM payout shall equal $2,250,000 plus $10,000 for each 1/10 of 1 percent of target reached up to the 2011 maximum SSM annual cap of $9,243,367.

SSM Calculation

SSM = {[(Net TRC - (Range End Percentage x Target TRC[1])) / (Payout Increment Percentage x Target TRC)] x Incremental Payout} + Base Payout
= {[(Net TRC - (75% x $252,652,675)) / (0.1% x $252,652,675)] x $10,000} + $2,250,000
= {[($379,580,963 - $189,489,506)/$252,653] x $10,000} + $2,250,000
= $752.38 x $10,000 + $2,250,000
= $9,773,825[2]

[1] 2011 TRC Target is $252,652,675

[2] SSM incentive without Cap. 2011 SSM cap is $9,243,367

Gross TRC of $389,086,629 less DSM costs other than incentives equals net TRC of $379,580,963 as reflected above

01 North Residential	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Residential Existing Homes					
ESK - Install - Faucet Aerator - Bath - 1.5 gpm	132	3	$ 19.91	419	$ 2,627.71
ESK - Install - Faucet Aerator - Kitchen - 1.5 gpm	132	10	$ 65.61	1,363	$ 8,660.11
ESK - Install - Pipe Insulation - 2m	132	14	$ 26.83	1,893	$ 3,541.71
ESK - Install - Showerhead - 1.25gpm	132	29	$ 174.31	3,829	$ 23,009.22
ESK - Install - Showerhead - 1.25gpm - Replacement	9	8	$ 48.75	71	$ 438.73
ESK - Pull - Faucet Aerator - Bath - 1.5pgm	13,614	2	$ 11.12	24,467	$ 151,424.76
ESK - Pull - Faucet Aerator - Kitchen - 1.5gpm	12,748	9	$ 56.47	113,528	$ 719,881.22
ESK - Pull - Pipe Insulation - 2m	12,748	11	$ 19.86	136,912	$ 253,116.14
ESK - Pull - Showerhead - 1.25gpm	13,795	18	$ 109.36	253,899	$ 1,508,563.79
ESK - Pull - Showerhead - 1.25gpm - Replacement	658	8	$ 48.75	5,202	$ 32,076.01
ESK - Push - Faucet Aerator - Bath - 1.5gpm	4,982	1	$ 7.33	5,992	$ 36,541.59
ESK - Push - Faucet Aerator - Kitchen - 1.5gpm	4,789	7	$ 43.15	32,737	$ 206,623.79
ESK - Push - Pipe Insulation - 2m	4,789	9	$ 16.49	43,112	$ 78,975.27
ESK - Push - Showerhead - 1.25gpm	5,059	16	$ 96.71	82,669	$ 489,248.96
ESK - Push - Showerhead - 1.25gpm - Replacement	410	10	$ 61.87	4,056	$ 25,364.94
Thermostat - Programmable	2,702	30	$ 86.35	81,627	$ 233,305.60
Low Income					
HHC - Faucet Aerator - Bath - 1.0gpm	7,343	8	$ 52.01	59,438	$ 381,930.51
HHC - Faucet Aerator - Kitchen - 1.5gpm	7,345	18	$ 113.45	130,885	$ 833,264.75
HHC - Pipe Insulation - 2m	7,369	16	$ 30.27	118,871	$ 223,027.19
HHC - Showerhead - 1.25gpm exist 2.0-2.5	3,394	36	$ 213.13	121,411	$ 723,351.31
HHC - Showerhead - 1.25gpm exist 2.6+	3,935	68	$ 361.94	269,286	$ 1,424,227.75
Thermostat - Programmable - HHC	1,930	52	$ 148.04	101,267	$ 285,713.41
Weatherization	99	0	$ -	75,133	$ -
Total	**108,246**	**385**	**$ 1,811.68**	**1,668,068**	**$ 7,644,914.46**

01 North Commercial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial New Buildings					
CEE Tier 2 Front-Loading Clothes Washer MF	4	105	$ 656.18	421	$ 2,624.72
Condensing Boiler - up to 299 MBtu/h	18	Variable	Variable	30,205	$ 50,305.45
Condensing Boiler - 300 to 999 MBtu/h	19	Variable	Variable	89,127	$ 176,516.82
Condensing Boiler - => 1,000 MBtu/h	3	Variable	Variable	44,460	$ 88,052.96
Condensing Gas Water Heater - 1000 gal/day	12	1,473	$ 1,250.31	17,681	$ 15,003.74

Custom - Agriculture	1	Variable	Variable	35,649	$ 86,667.13
Custom - New Construction	6	Variable	Variable	2,384	$ 5,614.10
Energy Star Fryer	5	866	$ 1,074.70	4,332	$ 5,373.50
ERV 2- over 1000 cfm MF,Healthcare,Nursing Hm	7	Variable	Variable	98,886	$ 184,197.05
ERV 3- up to 2000 cfm Hotel,Restaurant,Retail	4	Variable	Variable	17,535	$ 24,955.08
ERV 5- up to 2000 cfm Office,Warehouse,School	7	Variable	Variable	23,760	$ 20,495.50
ERV 6- over 2000 cfm Office,Warehouse,School	1	Variable	Variable	5,843	$ 5,039.88
HRV =>2,000cfm-Hotel,Restaurant,Retail,Rec	4	Variable	Variable	27,132	$ 24,338.38
HRV 500 to 1,999cfm-Hotel,Restaurant,Retail,Rec	2	Variable	Variable	8,140	$ 7,301.52
HRV-Healthcare & MF	43	Variable	Variable	17,955	$ 28,196.98
Infrared Heating - 1-20 to 99 MBtu/hr	20	Variable	Variable	14,872	$ 36,498.94
Infrared Heating - 2-100-300 MBtu/hr	2	Variable	Variable	2,876	$ 6,584.73
Commercial Existing Buildings					
CEE Tier 2 Front-Loading Clothes Washer Laundromat	14	105	$ 656.18	1,474	$ 9,186.51
CEE Tier 2 Front-Loading Clothes Washer MF	209	105	$ 656.18	22,008	$ 137,141.42
Condensing Boiler - up to 299 MBtu/h	17	Variable	Variable	33,242	$ 49,050.38
Condensing Boiler - 300 to 999 MBtu/h	43	Variable	Variable	214,021	$ 423,867.36
Condensing Boiler - => 1,000 MBtu/h	6	Variable	Variable	76,847	$ 152,194.64
Condensing Gas Water Heater - 1000 gal/day	2	1,473.45	$ 1,250.31	2,947	$ 2,500.62
Custom - Retrofit	22	Variable	Variable	25,859	$ 79,153.14
Dishwasher - Rack Conveyor - Single High Temperature	2	1,608	$ 13,893.94	3,216	$ 27,787.87
Dishwasher - Stationary Rack - High Temperature	6	495	$ 4,984.41	2,971	$ 29,906.44
Dishwasher - Stationary Rack - Low Temperature	30	673	$ 4,105.50	20,184	$ 123,164.89
Dishwasher - Undercounter - High Temperature	2	481	$ 3,261.85	961	$ 6,523.70
Energy Star Convection Oven	2	678	$ 776.71	1,355	$ 1,553.41
Energy Star Front Load Clothes Washer	21	40	$ 219.43	830	$ 4,608.13
Energy Star Fryer	24	866	$ 1,074.70	20,794	$ 25,792.79
ERV 1- up to 1000 cfm MF,Healthcare,NursingHm	1	Variable	Variable	4,651	$ 8,810.47
ERV 2- over 1000 cfm MF,Healthcare,Nursing Hm	1	Variable	Variable	6,977	$ 13,215.70
ERV 3- up to 2000 cfm Hotel,Restaurant,Retail	1	Variable	Variable	3,779	$ 5,587.58
ERV 5- up to 2000 cfm Office,Warehouse,School	8	Variable	Variable	14,874	$ 14,106.31
ERV 6- over 2000 cfm Office,Warehouse,School	3	Variable	Variable	22,470	$ 21,310.99
HRV =>2,000cfm-School,Office,Warehouse,Man	1	Variable	Variable	3,173	$ 800.12
HRV 500 to 1,999cfm-Hotel,Restaurant,Retail,Rec	1	Variable	Variable	1,488	$ 1,533.37
HRV-Healthcare & MF	116	Variable	Variable	49,428	$ 81,345.77
HWC - Bathroom Aerator - Hotel Motel - 1.0 gpm	1,311	3	$ 18.83	3,705	$ 24,687.92
HWC - Bathroom Aerator - Long Term Care and Retirement - 1.0 gpm	336	5	$ 22.69	1,582	$ 7,622.36
HWC - Bathroom Aerator - Multi Family - 1.0 gpm	1,954	4	$ 24.04	7,461	$ 46,969.94
HWC - Bathroom Aerator - Other Commercial Institutional - 1.0 gpm	385	4	$ 19.68	1,451	$ 7,576.66
HWC - Bathroom Aerator - Hotel Motel - 1.0 gpm - Rebate	371	3	$ 16.13	1,048	$ 5,984.74
HWC - Bathroom Aerator - Long Term Care and Retirement - 1.0 gpm - Reb	38	5	$ 19.99	179	$ 759.45
HWC - Bathroom Aerator - Multi Family - 1.0 gpm - Rebate	106	4	$ 21.34	405	$ 2,261.81
HWC - Bathroom Aerator - Other Commercial Institutional - 1.0 gpm - Reb	22	4	$ 16.98	83	$ 373.55
HWC - Kitchen Aerator - Multi Family - 1.5 gpm	1,751	6	$ 34.47	9,750	$ 60,360.57
HWC - Kitchen Aerator - Other Commercial Institutional - 1.5 gpm	281	10	$ 61.84	2,767	$ 17,376.92
HWC - Kitchen Aerator - Multi Family - 1.5 gpm - Rebate	100	6	$ 31.77	557	$ 3,177.21
HWC - Kitchen Aerator - Other Commercial Institutional - 1.5 gpm - Rebate	7	10	$ 59.14	69	$ 413.98
HWC - Showerhead - Hotel Motel - 1.25 gpm	1,490	15	$ 81.50	21,777	$ 121,433.13
HWC - Showerhead - Long Term Care and Retirement - 1.25 gpm & 1.5 gpr	320	19	$ 104.69	6,236	$ 33,501.13
HWC - Showerhead - Multi Family - 1.25 gpm	2,086	15	$ 86.96	31,877	$ 181,402.15
HWC - Showerhead - Multi Family - 1.25 gpm - Replacement	25	11	$ 69.09	287	$ 1,727.20
HWC - Showerhead - Other Commercial Institutional- 1.25 gpm	311	19	$ 106.57	6,061	$ 33,142.40
HWC - Showerhead - University College Dorms - 1.25 gpm	171	26	$ 136.68	4,443	$ 23,371.93
HWC - Showerhead - Hotel Motel - 1.25 gpm - Rebate	426	15	$ 78.80	6,226	$ 33,568.27
HWC - Showerhead - Long Term Care and Retirement - 1.25 gpm & 1.5 gpr	33	19	$ 101.99	643	$ 3,365.70
HWC - Showerhead - Multi Family - 1.25 gpm - Rebate	63	15	$ 84.26	963	$ 5,308.49
HWC - Showerhead - Multi Family - 1.25 gpm - Replacement Rebate	313	11	$ 66.39	3,587	$ 20,779.50
HWC - Showerhead - Other Commercial Institutional - 1.25 gpm - Rebate	9	19	$ 103.87	175	$ 934.80
Pre-Rinse Spray Nozzle - Full - 0.64 gpm	28	1,286	$ 3,306.84	36,008	$ 92,591.64
Pre-Rinse Spray Nozzle - Limited - 0.64 gpm	8	339	$ 761.02	2,712	$ 6,088.17
Pre-Rinse Spray Nozzle - Other - 0.64 gpm	3	318	$ 703.90	954	$ 2,111.71
Pre-Rinse Spray Nozzle - Full - 0.64 gpm replacing 1.6 gpm	54	457	$ 1,139.54	24,678	$ 61,535.30
Pre-Rinse Spray Nozzle - Limited - 0.64 gpm replacing 1.6 gpm	16	90	$ 104.25	1,440	$ 1,667.96
Pre-Rinse Spray Nozzle - Other - 0.64 gpm replacing 1.6 gpm	5	109	$ 157.26	545	$ 786.31
Thermostat - Programmable - Ware, Ind, Rec, Agr	256	86	$ 147.35	22,118	$ 37,721.25
Thermostat - Programmable - Food Service	29	55	$ 100.14	1,601	$ 2,903.95
Thermostat - Programmable - Office, Institution, Education	107	40	$ 36.83	4,280	$ 3,941.15
Infrared Heating - 1-20 to 99 MBtu/hr	6	Variable	Variable	4,474	$ 10,976.69
Infrared Heating - 2-100-300 MBtu/hr	23	Variable	Variable	41,440	$ 95,985.28
MUA - 2-MF&LTC Imp Effic 3000-5999 cfm	2	Variable	Variable	5,107	$ 7,138.49
Ozone WE =< 120 lbs cap & => 200,000 lbs/yr	3	Variable	Variable	21,509	$ 46,546.94
Total	**13,139**	**11,998**	**$ 41,685.21**	**1,253,006**	**$ 2,993,002.77**

10 North Commercial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial New Buildings					
CEE Tier 2 Front-Loading Clothes Washer MF	1	105	$ 656.18	105	$ 656.18
Condensing Boiler - up to 299 MBtu/h	2	Variable	Variable	2,257	$ 2,488.24
Condensing Boiler - 300 to 999 MBtu/h	4	Variable	Variable	18,752	$ 37,138.78
Condensing Boiler - => 1,000 MBtu/h	9	Variable	Variable	161,686	$ 320,219.25
Condensing Gas Water Heater - 1000 gal/day	5	1,473	$ 1,250.31	7,367	$ 6,251.56
DCKV 5000 - 9999 cfm	2	10,912	$ 36,812.69	21,823	$ 73,625.38
Dishwasher - Rack Conveyor - Single High Temperature	2	1,608	$ 13,893.94	3,216	$ 27,787.87
Dishwasher - Stationary Rack - Low Temperature	1	673	$ 4,105.50	673	$ 4,105.50
HRV =>2,000cfm-Hotel,Restaurant,Retail,Rec	1	Variable	Variable	4,748	$ 4,259.22
HRV 500 to 1,999cfm-Hotel,Restaurant,Retail,Rec	2	Variable	Variable	5,901	$ 5,293.60
HRV-Healthcare & MF	1	Variable	Variable	24,396	$ 38,311.11
Infrared Heating - 1-20 to 99 MBtu/hr	8	Variable	Variable	6,392	$ 15,535.84
Infrared Heating - 2-100-300 MBtu/hr	1	Variable	Variable	2,344	$ 5,493.56
Commercial Existing Buildings					
CEE Tier 2 Front-Loading Clothes Washer MF	101	105	$ 656.18	10,635	$ 66,274.08
Condensing Boiler - up to 299 MBtu/h	8	Variable	Variable	10,547	$ 10,380.41
Condensing Boiler - 300 to 999 MBtu/h	39	Variable	Variable	213,289	$ 422,419.38
Condensing Boiler - => 1,000 MBtu/h	22	Variable	Variable	349,377	$ 691,939.69
Condensing Gas Water Heater - 1000 gal/day	4	1,473	$ 1,250.31	5,894	$ 5,001.25
Custom - Agriculture	1	Variable	Variable	54,840	$ 130,977.73
Custom - Retrofit	10	Variable	Variable	181,184	$ 463,323.30
DCKV 5000 - 9999 cfm	1	10,912	$ 36,812.69	10,912	$ 36,812.69
Dishwasher - Rack Conveyor - Single High Temperature	2	1,608	$ 13,893.94	3,216	$ 27,787.87
Dishwasher - Stationary Rack - High Temperature	2	495	$ 4,984.41	990	$ 9,968.81
Dishwasher - Stationary Rack - Low Temperature	7	673	$ 4,105.50	4,710	$ 28,738.48
Energy Star Front Load Clothes Washer	23	40	$ 219.43	909	$ 5,047.00
Energy Star Fryer	23	866	$ 1,074.70	19,927	$ 24,718.09
Energy Star Steam Cooker	3	2,579	$ 3,931.03	7,738	$ 11,793.08
HWC - Bathroom Aerator - Hotel Motel - 1.0 gpm	396	3	$ 18.83	1,119	$ 7,457.22
HWC - Bathroom Aerator - Long Term Care and Retirement - 1.0 gpm	257	5	$ 22.69	1,210	$ 5,830.20
HWC - Bathroom Aerator - Multi Family - 1.0 gpm	624	4	$ 24.04	2,383	$ 14,999.61
HWC - Bathroom Aerator - Other Commercial Institutional - 1.0 gpm	136	4	$ 19.68	512	$ 2,676.43
HWC - Bathroom Aerator - Hotel Motel - 1.0 gpm - Rebate	267	3	$ 16.13	754	$ 4,307.08
HWC - Bathroom Aerator - Long Term Care and Retirement - 1.0 gpm - Reb	251	5	$ 19.99	1,182	$ 5,016.39
HWC - Bathroom Aerator - Multi Family - 1.0 gpm - Rebate	45	4	$ 21.34	172	$ 960.20
HWC - Kitchen Aerator - Multi Family - 1.5 gpm	586	6	$ 34.47	3,263	$ 20,200.62
HWC - Kitchen Aerator - Other Commercial Institutional - 1.5 gpm	86	10	$ 61.84	847	$ 5,318.20
HWC - Kitchen Aerator - Multi Family - 1.5 gpm - Rebate	47	6	$ 31.77	262	$ 1,493.29
HWC - Showerhead - Hotel Motel - 1.25 gpm	467	15	$ 81.50	6,826	$ 38,059.91
HWC - Showerhead - Long Term Care and Retirement - 1.25 gpm & 1.5 gpr	213	19	$ 104.69	4,151	$ 22,299.19
HWC - Showerhead - Multi Family - 1.25 gpm	877	15	$ 86.96	13,402	$ 76,265.43
HWC - Showerhead - Multi Family - 1.25 gpm - Replacement	376	11	$ 69.09	4,309	$ 25,977.15
HWC - Showerhead - Other Commercial Institutional- 1.25 gpm	154	19	$ 106.57	3,001	$ 16,411.35
HWC - Showerhead - Hotel Motel - 1.25 gpm - Rebate	47	15	$ 78.80	687	$ 3,703.54
HWC - Showerhead - Long Term Care and Retirement - 1.25 gpm & 1.5 gpr	135	19	$ 101.99	2,631	$ 13,768.79
HWC - Showerhead - Multi Family - 1.25 gpm - Rebate	140	15	$ 84.26	2,139	$ 11,796.64
Pre-Rinse Spray Nozzle - Full - 0.64 gpm	37	1,286	$ 3,306.84	47,582	$ 122,353.23
Pre-Rinse Spray Nozzle - Limited - 0.64 gpm	1	339	$ 761.02	339	$ 761.02
Pre-Rinse Spray Nozzle - Other - 0.64 gpm	1	318	$ 703.90	318	$ 703.90
Pre-Rinse Spray Nozzle - Full - 0.64 gpm replacing 1.6 gpm	55	457	$ 1,139.54	25,135	$ 62,674.85
Pre-Rinse Spray Nozzle - Limited - 0.64 gpm replacing 1.6 gpm	3	90	$ 104.25	270	$ 312.74
Pre-Rinse Spray Nozzle - Other - 0.64 gpm replacing 1.6 gpm	2	109	$ 157.26	218	$ 314.52
Thermostat - Programmable - Ware, Ind, Rec, Agr	19	86	$ 147.35	1,642	$ 2,799.62
Thermostat - Programmable - Office, Institution, Education	4	40	$ 36.83	160	$ 147.33
ERV 3- up to 2000 cfm Hotel,Restaurant,Retail	12	Variable	Variable	35,207	$ 52,055.27
ERV 4- over 2000 cfm Hotel,Restaurant,Retail	2	Variable	Variable	26,163	$ 38,683.27
ERV 5- up to 2000 cfm Office,Warehouse,School	10	Variable	Variable	27,830	$ 26,394.35
ERV 6- over 2000 cfm Office,Warehouse,School	8	Variable	Variable	68,586	$ 65,047.41
HRV =>2,000cfm-Hotel,Restaurant,Retail,Rec	3	Variable	Variable	40,589	$ 41,835.55
HRV =>2,000cfm-School,Office,Warehouse,Man	1	Variable	Variable	6,346	$ 1,600.25
HRV-Healthcare & MF	1	Variable	Variable	35,720	$ 58,786.47
Infrared Heating - 2-100-300 MBtu/hr	26	Variable	Variable	35,474	$ 82,414.76
Ozone WE =< 120 lbs cap & => 200,000 lbs/yr	2	Variable	Variable	12,515	$ 24,512.88
Ozone WE =< 120 lbs cap & 100,000 to 199,999lbs/yr	1	Variable	Variable	3,304	$ 1,709.29
Total	**5,577**	**36,426**	**$ 130,988.42**	**1,550,078**	**$ 3,335,995.92**

10 North Industrial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC

Commercial New Buildings					
Condensing Boiler - => 1,000 MBtu/h	9	Variable	Variable	266,760	$ 528,317.73
ERV 6- over 2000 cfm Office,Warehouse,School	1	Variable	Variable	4,674	$ 4,031.90
Infrared Heating - 2-100-300 MBtu/hr	10	Variable	Variable	17,577	$ 40,540.02
Commercial Existing Buildings					
Custom - Retrofit	1	Variable	Variable	82,660	$ 223,260.25
Infrared Heating - 2-100-300 MBtu/hr	6	Variable	Variable	10,120	$ 24,057.70
Pre-Rinse Spray Nozzle - Full - 0.64 gpm replacing 1.6 gpm	1	457	$ 1,139.54	457	$ 1,139.54
Thermostat - Programmable - Ware, Ind, Rec, Agr	16	86.4	$ 147.35	1382.4	$ 2,357.58
Distribution Contract Markets					
Custom - DC	3	Variable	Variable	100,849	$ 230,496.92
Total	**47**	**-**	**-**	**484,480**	**$ 1,054,201.65**

20 North Industrial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial New Buildings					
Condensing Boiler - => 1,000 MBtu/h	3	Variable	Variable	74,100	$ 146,754.93
Infrared Heating - 2-100-300 MBtu/hr	2	Variable	Variable	2,663	$ 6,134.60
Commercial Existing Buildings					
ERV 2- over 1000 cfm MF,Healthcare,Nursing Hm	2	Variable	Variable	68,605	$ 129,954.37
HRV-Healthcare & MF	2	Variable	Variable	16,074	$ 26,453.91
Distribution Contract Markets					
Custom - DC	22	Variable	Variable	4,415,832	$ 11,955,094.76
Total	**31**	**-**	**-**	**4,577,275**	**$ 12,264,392.57**

100 North Industrial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Distribution Contract Markets					
Custom - DC	30	Variable	Variable	12,066,785	$ 29,685,297.54
Total	**30**	**-**	**-**	**12,066,785**	**$ 29,685,297.54**

M1 South Residential	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Residential New Homes					
Faucet Aerator - Bath - 1.5gpm	234	4	$ 25.29	941	$ 5,916.88
Faucet Aerator - Kitchen - 1.5gpm	53	13	$ 78.96	675	$ 4,184.72
Showerhead - 1.25gpm	96	40	$ 239.21	3,802	$ 22,964.61
Residential Existing Homes					
ESK - Install - Faucet Aerator - Bath - 1.5 gpm	371	3	$ 19.91	1,178	$ 7,385.45
ESK - Install - Faucet Aerator - Kitchen - 1.5 gpm	371	10	$ 65.61	3,830	$ 24,340.14
ESK - Install - Pipe Insulation - 2m	371	14	$ 26.83	5,321	$ 9,954.34
ESK - Install - Showerhead - 1.25gpm	266	29	$ 174.31	7,716	$ 46,367.07
ESK - Install - Showerhead - 1.25gpm exist 2.6+	105	58	$ 306.60	6,091	$ 32,193.00
ESK - Install - Showerhead - 1.25gpm - Replacement	71	8	$ 48.75	561	$ 3,461.09
ESK - Pull - Faucet Aerator - Bath - 1.5pgm	46,780	2	$ 11.12	84,072	$ 520,321.02
ESK - Pull - Faucet Aerator - Kitchen - 1.5gpm	43,426	9	$ 56.47	386,731	$ 2,452,271.89
ESK - Pull - Pipe Insulation - 2m	43,426	11	$ 19.86	466,390	$ 862,238.90
ESK - Pull - Showerhead - 1.25gpm	47,481	18	$ 109.36	873,896	$ 5,192,324.55
ESK - Pull - Showerhead - 1.25gpm - Replacement	2,549	8	$ 48.75	20,151	$ 124,257.97
ESK - Push - Faucet Aerator - Bath - 1.5gpm	15,302	1	$ 7.33	18,403	$ 112,235.92
ESK - Push - Faucet Aerator - Kitchen - 1.5gpm	14,795	7	$ 43.15	101,137	$ 638,337.64
ESK - Push - Pipe Insulation - 2m	14,795	9	$ 16.49	133,190	$ 243,983.94
ESK - Push - Showerhead - 1.25gpm	15,505	16	$ 96.71	253,367	$ 1,499,467.30
ESK - Push - Showerhead - 1.25gpm - Replacement	1,078	10	$ 61.87	10,665	$ 66,691.24
Thermostat - Programmable	8,015	30	$ 86.35	242,133	$ 692,059.35
Low Income					
HHC - Faucet Aerator - Bath - 1.0gpm	21,523	8	$ 52.01	174,219	$ 1,119,473.01
HHC - Faucet Aerator - Kitchen - 1.5gpm	21,521	18	$ 113.45	383,495	$ 2,441,482.75
HHC - Pipe Insulation - 2m	21,541	16	$ 30.27	347,484	$ 651,951.25
HHC - Showerhead - 1.25gpm exist 2.0-2.5	8,947	36	$ 213.13	320,053	$ 1,906,842.72
HHC - Showerhead - 1.25gpm exist 2.6+	12,416	68	$ 361.94	849,672	$ 4,493,827.64
Thermostat - Programmable - HHC	5,774	52	$ 148.04	302,962	$ 854,771.62
Weatherization	351	0	$ -	439,366	$ -
Total	**347,163**	**499**	**$ 2,461.73**	**5,437,501**	**$ 24,029,306.01**

M1 South Commercial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial New Buildings					
CEE Tier 2 Front-Loading Clothes Washer MF	16	105	$ 656.18	1,685	$ 10,498.86
Condensing Boiler - up to 299 MBtu/h	77	Variable	Variable	116,697	$ 193,351.95
Condensing Boiler - 300 to 999 MBtu/h	35	Variable	Variable	175,321	$ 347,222.15
Condensing Boiler - => 1,000 MBtu/h	23	Variable	Variable	426,925	$ 845,523.61
Custom - Agriculture	5	Variable	Variable	217,334	$ 535,907.18
Custom - New Construction	12	Variable	Variable	3,054	$ 8,028.71
Condensing Gas Water Heater - 1000 gal/day	15	1,473	$ 1,250.31	22,102	$ 18,754.67
DCKV < 5000 cfm	1	4,561	$ 12,307.51	4,561	$ 12,307.51
DCKV 5000 - 9999 cfm	2	10,912	$ 36,812.69	21,823	$ 73,625.38
Dishwasher - Rack Conveyor - Single High Temperature	3	1,608	$ 13,893.94	4,825	$ 41,681.81
Dishwasher - Stationary Rack - High Temperature	4	495	$ 4,984.41	1,981	$ 19,937.63
Dishwasher - Stationary Rack - Low Temperature	1	673	$ 4,105.50	673	$ 4,105.50
Dishwasher - Undercounter - High Temperature	9	481	$ 3,261.85	4,325	$ 29,356.65
Energy Star Front Load Clothes Washer	1	40	$ 219.43	40	$ 219.43
Energy Star Fryer	10	866	$ 1,074.70	8,664	$ 10,747.00
ERV 1- up to 1000 cfm MF,Healthcare,NursingHm	88	Variable	Variable	56,131	$ 104,555.31
ERV 2- over 1000 cfm MF,Healthcare,Nursing Hm	3	Variable	Variable	54,267	$ 101,083.75
ERV 3- up to 2000 cfm Hotel,Restaurant,Retail	20	Variable	Variable	54,455	$ 77,499.63
ERV 4- over 2000 cfm Hotel,Restaurant,Retail	16	Variable	Variable	161,916	$ 230,437.37
ERV 5- up to 2000 cfm Office,Warehouse,School	9	Variable	Variable	15,775	$ 13,607.67
ERV 6- over 2000 cfm Office,Warehouse,School	1	Variable	Variable	4,577	$ 3,947.90
HRV 500 to 1,999cfm-Hotel,Restaurant,Retail,Rec	1	Variable	Variable	1,126	$ 1,010.04
HRV-Healthcare & MF	109	Variable	Variable	124,037	$ 194,786.46
Infrared Heating - 1-20 to 99 MBtu/hr	22	Variable	Variable	17,418	$ 42,385.97
Infrared Heating - 2-100-300 MBtu/hr	137	Variable	Variable	188,079	$ 437,623.36
MUA - 1-MF&LTC Imp Effic 1700-2999 cfm	1	Variable	Variable	1,596	$ 1,920.84
Commercial Existing Buildings					
CEE Tier 2 Front-Loading Clothes Washer Laundromat	13	105	$ 656.18	1,369	$ 8,530.33
CEE Tier 2 Front-Loading Clothes Washer MF	416	105	$ 656.18	43,805	$ 272,970.49
Condensing Boiler - up to 299 MBtu/h	56	Variable	Variable	123,253	$ 202,441.30
Condensing Boiler - 300 to 999 MBtu/h	79	Variable	Variable	401,573	$ 795,314.62
Condensing Boiler - => 1,000 MBtu/h	19	Variable	Variable	267,550	$ 529,883.12
Condensing Gas Water Heater - 1000 gal/day	17	1,473	$ 1,250.31	25,049	$ 21,255.30
Custom - Agriculture	1	Variable	Variable	12,104	$ 8,384.95
Custom - Retrofit	111	Variable	Variable	207,750	$ 497,085.14
DCKV < 5000 cfm	1	4,561	$ 12,307.51	4,561	$ 12,307.51
DCKV 5000 - 9999 cfm	3	10,912	$ 36,812.69	32,735	$ 110,438.06
Dishwasher - Rack Conveyor - Single High Temperature	8	1,608	$ 13,893.94	12,866	$ 111,151.50
Dishwasher - Stationary Rack - High Temperature	16	495	$ 4,984.41	7,923	$ 79,750.50
Dishwasher - Stationary Rack - Low Temperature	89	673	$ 4,105.50	59,879	$ 365,389.19
Dishwasher - Undercounter - High Temperature	6	481	$ 3,261.85	2,884	$ 19,571.10
Energy Star Front Load Clothes Washer	295	40	$ 219.43	11,658	$ 64,733.25
Energy Star Convection Oven	2	678	$ 776.71	1,355	$ 1,553.41
Energy Star Fryer	81	866	$ 1,074.70	70,178	$ 87,050.67
High Efficiency Under-Fired Broiler	1	1,342	$ 1,906.65	1,342	$ 1,906.65
HWC - Bathroom Aerator - Hotel Motel - 1.0 gpm	1,082	3	$ 18.83	3,058	$ 20,375.54
HWC - Bathroom Aerator - Long Term Care and Retirement - 1.0 gpm	603	5	$ 22.69	2,840	$ 13,679.42
HWC - Bathroom Aerator - Multi Family - 1.0 gpm	5,461	4	$ 24.04	20,852	$ 131,270.63
HWC - Bathroom Aerator - Other Commercial Institutional - 1.0 gpm	666	4	$ 19.68	2,509	$ 13,106.64
HWC - Bathroom Aerator - University College Dorms - 1.0 gpm	254	4	$ 17.52	957	$ 4,448.98
HWC - Bathroom Aerator - Hotel Motel - 1.0 gpm - Rebate	61	3	$ 16.13	172	$ 984.01
HWC - Bathroom Aerator - Long Term Care and Retirement - 1.0 gpm - Reb	75	5	$ 19.99	353	$ 1,498.92
HWC - Bathroom Aerator - Multi Family - 1.0 gpm - Rebate	471	4	$ 21.34	1,798	$ 10,050.12
HWC - Bathroom Aerator - Other Commercial Institutional - 1.0 gpm - Reb	16	4	$ 16.98	60	$ 271.67
HWC - Bathroom Aerator - University College Dorms - 1.0 gpm - Rebate	1,051	4	$ 14.82	3,960	$ 15,571.28
HWC - Kitchen Aerator - Multi Family - 1.5 gpm	5,499	6	$ 34.47	30,621	$ 189,561.84
HWC - Kitchen Aerator - Other Commercial Institutional - 1.5 gpm	526	10	$ 61.84	5,179	$ 32,527.61
HWC - Kitchen Aerator - University College Dorms - 1.5 gpm	194	10	$ 61.84	1,910	$ 11,996.88
HWC - Kitchen Aerator - Multi Family - 1.5 gpm - Rebate	606	6	$ 31.77	3,374	$ 19,253.87
HWC - Kitchen Aerator - Other Commercial Institutional - 1.5 gpm - Rebate	4	10	$ 59.14	39	$ 236.56
HWC - Kitchen Aerator - University College Dorms - 1.5 gpm - Rebate	817	10	$ 59.14	8,044	$ 48,317.03
HWC - Showerhead - Hotel Motel - 1.25 gpm	1,232	15	$ 81.50	18,006	$ 100,406.45
HWC - Showerhead - Long Term Care and Retirement - 1.25 gpm & 1.5 gpr	750	19	$ 104.69	14,616	$ 78,518.28
HWC - Showerhead - Multi Family - 1.25 gpm	5,569	15	$ 86.96	85,101	$ 484,289.83
HWC - Showerhead - Multi Family - 1.25 gpm - Replacement	644	11	$ 69.09	7,381	$ 44,492.78
HWC - Showerhead - Other Commercial Institutional- 1.25 gpm	505	19	$ 106.57	9,841	$ 53,816.44
HWC - Showerhead - University College Dorms - 1.25 gpm	219	26	$ 136.68	5,690	$ 29,932.48
HWC - Showerhead - Hotel Motel - 1.25 gpm - Rebate	61	15	$ 78.80	892	$ 4,806.72
HWC - Showerhead - Long Term Care and Retirement - 1.25 gpm & 1.5 gpr	61	19	$ 101.99	1,189	$ 6,221.45
HWC - Showerhead - Multi Family - 1.25 gpm - Rebate	730	15	$ 84.26	11,155	$ 61,511.06
HWC - Showerhead - Multi Family - 1.25 gpm - Replacement Rebate	573	11	$ 66.39	6,567	$ 38,040.42

HWC - Showerhead - Other Commercial Institutional - 1.25 gpm - Rebate	52	19	$ 103.87	1,013	$ 5,401.09
HWC - Showerhead - University College Dorms - 1.25 gpm - Rebate	1,071	26	$ 133.98	27,828	$ 143,490.40
ERV 1- up to 1000 cfm MF,Healthcare,NursingHm	2	Variable	Variable	5,669	$ 10,737.76
ERV 2- over 1000 cfm MF,Healthcare,Nursing Hm	7	Variable	Variable	75,582	$ 143,170.07
ERV 3- up to 2000 cfm Hotel,Restaurant,Retail	19	Variable	Variable	51,034	$ 75,456.26
ERV 4- over 2000 cfm Hotel,Restaurant,Retail	3	Variable	Variable	29,878	$ 44,175.34
ERV 5- up to 2000 cfm Office,Warehouse,School	62	Variable	Variable	82,105	$ 77,869.20
ERV 6- over 2000 cfm Office,Warehouse,School	8	Variable	Variable	101,154	$ 95,934.66
HRV =>2,000cfm-Hotel,Restaurant,Retail,Rec	1	Variable	Variable	45,015	$ 46,397.34
HRV 500 to 1,999cfm-Hotel,Restaurant,Retail,Rec	2	Variable	Variable	4,215	$ 4,344.56
HRV-Healthcare & MF	3	Variable	Variable	2,657	$ 4,372.24
Infrared Heating - 1-20 to 99 MBtu/hr	52	Variable	Variable	36,220	$ 88,509.46
Infrared Heating - 2-100-300 MBtu/hr	237	Variable	Variable	328,911	$ 767,761.81
MUA - 2-MF&LTC Imp Effic 3000-5999 cfm	2	Variable	Variable	5,912	$ 8,523.15
MUA - 8-Other Comm Imp Effic => 4000 cfm	5	Variable	Variable	11,821	$ 6,475.35
MUA -12-Other Comm Effic + VFD =>6000 cfm	2	Variable	Variable	40,117	$ 86,667.93
Ozone WE =< 120 lbs cap & 100,000 to 199,999lbs/yr	24	Variable	Variable	80,751	$ 46,196.26
Pre-Rinse Spray Nozzle - Full - 0.64 gpm	38	1,286	$ 3,306.84	48,868	$ 125,660.08
Pre-Rinse Spray Nozzle - Limited - 0.64 gpm	34	339	$ 761.02	11,526	$ 25,874.72
Pre-Rinse Spray Nozzle - Other - 0.64 gpm	13	318	$ 703.90	4,134	$ 9,150.72
Pre-Rinse Spray Nozzle - Full - 0.64 gpm replacing 1.6 gpm	167	457	$ 1,139.54	76,319	$ 190,303.62
Pre-Rinse Spray Nozzle - Limited - 0.64 gpm replacing 1.6 gpm	130	90	$ 104.25	11,700	$ 13,552.16
Pre-Rinse Spray Nozzle - Other - 0.64 gpm replacing 1.6 gpm	32	109	$ 157.26	3,488	$ 5,032.36
Thermostat - Programmable - Ware, Ind, Rec, Agr	1,282	86	$ 147.35	110,765	$ 188,900.97
Thermostat - Programmable - Food Service	68	55	$ 100.14	3,754	$ 6,809.27
Thermostat - Programmable - Office, Institution, Education	359	40	$ 36.83	14,360	$ 13,223.12
Total	**33,240**	**47,634**	**$ 168,584.66**	**4,438,181**	**$ 10,199,020.25**

M1 South Industrial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial New Buildings					
Infrared Heating - 2-100-300 MBtu/hr	2	Variable	Variable	3,995	$ 9,524.21
Commercial Existing Buildings					
Custom - Retrofit	1	Variable	Variable	10,726	$ 13,600.99
Infrared Heating - 1-20 to 99 MBtu/hr	3	Variable	Variable	2,131	$ 5,019.22
Infrared Heating - 2-100-300 MBtu/hr	34	Variable	Variable	51,827	$ 121,299.33
Pre-Rinse Spray Nozzle - Limited - 0.64 gpm	1	339	$ 761.02	339	$ 761.02
Pre-Rinse Spray Nozzle - Full - 0.64 gpm replacing 1.6 gpm	3	457	$ 1,139.54	1,371	$ 3,418.63
Thermostat - Programmable - Ware, Ind, Rec, Agr	469	86	$ 147.35	40,522	$ 69,106.52
Thermostat - Programmable - Food Service	1	55	$ 100.14	55	$ 100.14
Thermostat - Programmable - Office, Institution, Education	3	40	$ 36.83	120	$ 110.50
Distribution Contract Markets					
Custom - Agriculture	2	Variable	Variable	69,759	$ 11,916.51
Custom - DC	2	Variable	Variable	1,064,921	$ 2,856,474.62
Total	**521**	**978**	**$ 2,184.88**	**1,245,765**	**$ 3,091,331.68**

M2 South Commercial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial New Buildings					
CEE Tier 2 Front-Loading Clothes Washer MF	6	105	$ 656.18	632	$ 3,937.07
Condensing Boiler - up to 299 MBtu/h	3	Variable	Variable	8,259	$ 16,690.54
Condensing Boiler - 300 to 999 MBtu/h	5	Variable	Variable	37,030	$ 73,338.33
Condensing Boiler - => 1,000 MBtu/h	12	Variable	Variable	275,988	$ 546,593.61
Condensing Gas Water Heater - 1000 gal/day	12	1,473	$ 1,250.31	17,681	$ 15,003.74
Custom - Agriculture	2	Variable	Variable	142,967	$ 369,040.61
DCKV < 5000 cfm	1	4,561	$ 12,307.51	4,561	$ 12,307.51
Dishwasher - Rack Conveyor - Single High Temperature	2	1,608	$ 13,893.94	3,216	$ 27,787.87
Dishwasher - Stationary Rack - High Temperature	1	495	$ 4,984.41	495	$ 4,984.41
Dishwasher - Undercounter - High Temperature	1	481	$ 3,261.85	481	$ 3,261.85
ERV 2- over 1000 cfm MF,Healthcare,Nursing Hm	5	Variable	Variable	77,015	$ 143,457.24
ERV 4- over 2000 cfm Hotel,Restaurant,Retail	6	Variable	Variable	96,989	$ 138,034.14
ERV 5- up to 2000 cfm Office,Warehouse,School	5	Variable	Variable	9,854	$ 8,500.59
ERV 6- over 2000 cfm Office,Warehouse,School	6	Variable	Variable	72,564	$ 62,595.27
Energy Star Steam Cooker	1	2,579	$ 3,931.03	2,579	$ 3,931.03
HRV =>2,000cfm-Hotel,Restaurant,Retail,Rec	16	Variable	Variable	720,762	$ 646,549.18
HRV-Healthcare & MF	1	Variable	Variable	4,879	$ 7,662.22
Infrared Heating - 2-100-300 MBtu/hr	4	Variable	Variable	5,859	$ 13,394.51
Commercial Existing Buildings					
CEE Tier 2 Front-Loading Clothes Washer Laundromat	5	105	$ 656.18	527	$ 3,280.90
CEE Tier 2 Front-Loading Clothes Washer MF	620	105	$ 656.18	65,286	$ 406,831.01

Condensing Boiler - up to 299 MBtu/h	15	Variable	Variable	27,446	$ 38,095.20
Condensing Boiler - 300 to 999 MBtu/h	94	Variable	Variable	497,701	$ 985,696.09
Condensing Boiler - => 1,000 MBtu/h	60	Variable	Variable	973,664	$ 1,928,340.15
Condensing Gas Water Heater - 1000 gal/day	44	1,473	$ 1,250.31	64,832	$ 55,013.71
Custom - Agriculture	1	Variable	Variable	12,722	$ 21,977.89
Custom - Retrofit	106	Variable	Variable	1,316,433	$ 2,800,185.21
DCKV 5000 - 9999 cfm	4	10,912	$ 36,812.69	43,647	$ 147,250.75
Destratification Fan	10	Variable	Variable	144,450	$ 298,169.11
Dishwasher - Rack Conveyor - Single High Temperature	6	1,608	$ 13,893.94	9,649	$ 83,363.62
Dishwasher - Stationary Rack - High Temperature	2	495	$ 4,984.41	990	$ 9,968.81
Dishwasher - Stationary Rack - Low Temperature	16	673	$ 4,105.50	10,765	$ 65,687.94
Dishwasher - Undercounter - High Temperature	5	481	$ 3,261.85	2,403	$ 16,309.25
Energy Star Convection Oven	3	678	$ 776.71	2,033	$ 2,330.12
Energy Star Front Load Clothes Washer	218	40	$ 219.43	8,615	$ 47,836.78
Energy Star Fryer	3	866	$ 1,074.70	2,599	$ 3,224.10
Energy Star Steam Cooker	1	2,579	$ 3,931.03	2,579	$ 3,931.03
ERV 2- over 1000 cfm MF,Healthcare,Nursing Hm	1	Variable	Variable	6,977	$ 13,215.70
ERV 3- up to 2000 cfm Hotel,Restaurant,Retail	1	Variable	Variable	6,460	$ 9,551.42
ERV 4- over 2000 cfm Hotel,Restaurant,Retail	3	Variable	Variable	38,114	$ 56,353.41
ERV 5- up to 2000 cfm Office,Warehouse,School	29	Variable	Variable	50,709	$ 48,092.46
ERV 6- over 2000 cfm Office,Warehouse,School	17	Variable	Variable	187,590	$ 177,911.61
HRV =>2,000cfm-Hotel,Restaurant,Retail,Rec	3	Variable	Variable	107,856	$ 111,167.06
HRV =>2,000cfm-School,Office,Warehouse,Man	1	Variable	Variable	8,572	$ 2,161.53
HRV 500 to 1,999cfm-Hotel,Restaurant,Retail,Rec	2	Variable	Variable	6,447	$ 6,644.62
HRV-Healthcare & MF	3	Variable	Variable	70,145	$ 115,441.92
HWC - Bathroom Aerator - Hotel Motel - 1.0 gpm	398	3	$ 18.83	1,125	$ 7,494.88
HWC - Bathroom Aerator - Long Term Care and Retirement - 1.0 gpm	807	5	$ 22.69	3,801	$ 18,307.29
HWC - Bathroom Aerator - Multi Family - 1.0 gpm	2,841	4	$ 24.04	10,848	$ 68,291.50
HWC - Bathroom Aerator - Other Commercial Institutional - 1.0 gpm	186	4	$ 19.68	701	$ 3,660.41
HWC - Bathroom Aerator - University College Dorms - 1.0 gpm	450	4	$ 17.52	1,695	$ 7,882.06
HWC - Bathroom Aerator - Hotel Motel - 1.0 gpm - Rebate	472	3	$ 16.13	1,334	$ 7,614.01
HWC - Bathroom Aerator - Long Term Care and Retirement - 1.0 gpm - Reb	287	5	$ 19.99	1,352	$ 5,735.87
HWC - Bathroom Aerator - Multi Family - 1.0 gpm - Rebate	390	4	$ 21.34	1,489	$ 8,321.76
HWC - Bathroom Aerator - Other Commercial Institutional - 1.0 gpm - Reb	34	4	$ 16.98	128	$ 577.31
HWC - Bathroom Aerator - University College Dorms - 1.0 gpm - Rebate	371	4	$ 14.82	1,398	$ 5,496.62
HWC - Kitchen Aerator - Multi Family - 1.5 gpm	2,720	6	$ 34.47	15,146	$ 93,763.99
HWC - Kitchen Aerator - Other Commercial Institutional - 1.5 gpm	83	10	$ 61.84	817	$ 5,132.68
HWC - Kitchen Aerator - University College Dorms - 1.5 gpm	248	10	$ 61.84	2,442	$ 15,336.21
HWC - Kitchen Aerator - Multi Family - 1.5 gpm - Rebate	393	6	$ 31.77	2,188	$ 12,486.42
HWC - Kitchen Aerator - Other Commercial Institutional - 1.5 gpm - Rebate	17	10	$ 59.14	167	$ 1,005.37
HWC - Kitchen Aerator - University College Dorms - 1.5 gpm - Rebate	194	10	$ 59.14	1,910	$ 11,473.08
HWC - Showerhead - Hotel Motel - 1.25 gpm	570	15	$ 81.50	8,331	$ 46,454.29
HWC - Showerhead - Long Term Care and Retirement - 1.25 gpm & 1.5 gpr	200	19	$ 104.69	3,898	$ 20,938.21
HWC - Showerhead - Multi Family - 1.25 gpm	2,836	15	$ 86.96	43,338	$ 246,623.44
HWC - Showerhead - Multi Family - 1.25 gpm - Replacement	2,090	11	$ 69.09	23,953	$ 144,394.27
HWC - Showerhead - Other Commercial Institutional- 1.25 gpm	318	19	$ 106.57	6,197	$ 33,888.37
HWC - Showerhead - University College Dorms - 1.25 gpm	607	26	$ 136.68	15,772	$ 82,963.53
HWC - Showerhead - Hotel Motel - 1.25 gpm - Rebate	323	15	$ 78.80	4,721	$ 25,451.99
HWC - Showerhead - Long Term Care and Retirement - 1.25 gpm & 1.5 gpr	257	19	$ 101.99	5,008	$ 26,211.70
HWC - Showerhead - Multi Family - 1.25 gpm - Rebate	630	15	$ 84.26	9,627	$ 53,084.88
HWC - Showerhead - Multi Family - 1.25 gpm - Replacement Rebate	1,025	11	$ 66.39	11,747	$ 68,047.87
HWC - Showerhead - Other Commercial Institutional - 1.25 gpm - Rebate	99	19	$ 103.87	1,929	$ 10,282.85
HWC - Showerhead - University College Dorms - 1.25 gpm - Rebate	324	26	$ 133.98	8,419	$ 43,408.86
Infrared Heating - 1-20 to 99 MBtu/hr	16	Variable	Variable	12,837	$ 31,184.22
Infrared Heating - 2-100-300 MBtu/hr	185	Variable	Variable	219,718	$ 511,472.53
MUA - 8-Other Comm Imp Effic => 4000 cfm	1	Variable	Variable	1,948	$ 921.09
MUA -11-Other Comm Effic + VFD 1700-5999 cfm	1	Variable	Variable	3,933	$ 7,832.41
Ozone WE =< 120 lbs cap & => 200,000 lbs/yr	31	Variable	Variable	230,190	$ 509,292.94
Ozone WE =< 120 lbs cap & 100,000 to 199,999lbs/yr	1	Variable	Variable	3,863	$ 3,703.18
Ozone WE > 120 lbs cap & 260,000 to 999,999 lbs/yr	1	Variable	Variable	16,062	$ 29,520.95
Pre-Rinse Spray Nozzle - Full - 0.64 gpm	62	1,286	$ 3,306.84	79,732	$ 205,024.34
Pre-Rinse Spray Nozzle - Other - 0.64 gpm	40	318	$ 703.90	12,720	$ 28,156.07
Pre-Rinse Spray Nozzle - Full - 0.64 gpm replacing 1.6 gpm	172	457	$ 1,139.54	78,604	$ 196,001.34
Pre-Rinse Spray Nozzle - Limited - 0.64 gpm replacing 1.6 gpm	27	90	$ 104.25	2,430	$ 2,814.68
Pre-Rinse Spray Nozzle - Other - 0.64 gpm replacing 1.6 gpm	57	109	$ 157.26	6,213	$ 8,963.88
Thermostat - Programmable - Ware, Ind, Rec, Agr	230	86	$ 147.35	19,872	$ 33,890.19
Thermostat - Programmable - Food Service	5	55	$ 100.14	276	$ 500.68
Thermostat - Programmable - Office, Institution, Education	16	40	$ 36.83	640	$ 589.33
Distribution Contract Markets					
Custom - Agriculture	2	Variable	Variable	40,457	$ 39,205.56
Total	**21,379**	**34,061**	**$ 119,259.22**	**6,069,999**	**$ 12,238,504.24**

M2 South Industrial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial New Buildings					
Condensing Boiler - => 1,000 MBtu/h	3	Variable	Variable	99,620	$ 197,297.32
Infrared Heating - 2-100-300 MBtu/hr	62	Variable	Variable	112,549	$ 263,325.38
Commercial Existing Buildings					
CEE Tier 2 Front-Loading Clothes Washer MF	18	105	$ 656.18	1,895	$ 11,811.22
Custom - Retrofit	11	Variable	Variable	136,401	$ 1,129,469.69
Destratification Fan	15	Variable	Variable	193,050	$ 388,153.04
Dishwasher - Undercounter - High Temperature	1	481	$ 3,261.85	481	$ 3,261.85
HWC - Bathroom Aerator - University College Dorms - 1.0 gpm	218	4	$ 17.52	821	$ 3,818.42
HWC - Kitchen Aerator - University College Dorms - 1.5 gpm	140	10	$ 61.84	1,378	$ 8,657.54
HWC - Showerhead - University College Dorms - 1.25 gpm	219	26	$ 136.68	5,690	$ 29,932.48
Infrared Heating - 1-20 to 99 MBtu/hr	8	Variable	Variable	5,113	$ 12,591.01
Infrared Heating - 2-100-300 MBtu/hr	83	Variable	Variable	123,202	$ 286,843.42
Pre-Rinse Spray Nozzle - Other - 0.64 gpm replacing 1.6 gpm	2	109	$ 157.26	218	$ 314.52
Thermostat - Programmable - Ware, Ind, Rec, Agr	419	86	$ 147.35	36,202	$ 61,739.08
Distribution Contract Markets					
Custom - Agriculture	20	Variable	Variable	1,207,599	$ 2,203,528.82
Custom - DC	56	Variable	Variable	1,205,641	$ 4,121,482.14
Total	**1,275**	**821**	**$ 4,438.67**	**3,129,861**	**$ 8,722,225.93**

M4 South Industrial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial New Buildings					
Infrared Heating - 2-100-300 MBtu/hr	5	Variable	Variable	8,522	$ 20,139.59
Commercial Existing Buildings					
Condensing Gas Water Heater - 1000 gal/day	5	1,473	$ 1,250.31	7,367	$ 6,251.56
Destratification Fan	11	Variable	Variable	174,960	$ 368,174.44
Infrared Heating - 1-20 to 99 MBtu/hr	2	Variable	Variable	1,651	$ 3,996.49
Infrared Heating - 2-100-300 MBtu/hr	5	Variable	Variable	8,256	$ 19,576.93
Thermostat - Programmable - Ware, Ind, Rec, Agr	216	86	$ 147.35	18,662	$ 31,827.31
Distribution Contract Markets					
Custom - Agriculture	9	Variable	Variable	1,013,835	$ 1,301,948.96
Custom - DC	158	Variable	Variable	6,747,797	$ 19,830,184.76
Total	**411**	**1,560**	**$ 1,397.66**	**7,981,051**	**$ 21,582,100.04**

M5 South Industrial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial Existing Buildings					
CEE Tier 2 Front-Loading Clothes Washer MF	3	105	$ 656.18	316	$ 1,968.54
ERV 5- up to 2000 cfm Office,Warehouse,School	1	Variable	Variable	1,546	$ 1,466.35
HWC - Bathroom Aerator - University College Dorms - 1.0 gpm	49	4	$ 17.52	185	$ 858.27
HWC - Showerhead - University College Dorms - 1.25 gpm	40	26	$ 136.68	1,039	$ 5,467.12
Infrared Heating - 2-100-300 MBtu/hr	3	Variable	Variable	6,392	$ 15,130.31
Thermostat - Programmable - Ware, Ind, Rec, Agr	10	86	$ 147.35	864	$ 1,473.49
Distribution Contract Markets					
Custom - Agriculture	64	Variable	Variable	6,364,890	$ 6,742,554.51
Custom - DC	358	Variable	Variable	8,039,095	$ 34,500,438.35
Total	**528**	**221**	**$ 957.72**	**14,414,327**	**$ 41,269,356.92**

M7 South Industrial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Distribution Contract Markets					
Custom - DC	29	Variable	Variable	12,779,564	$ 25,692,250.66
Total	**29**	**-**	**-**	**12,779,564**	**$ 25,692,250.66**

T1 South Industrial	Units	LRAM m3 per Unit	SSM TRC per Unit	Total LRAM m3	Total Gross SSM TRC
Commercial Existing Buildings					
Energy Star Front Load Clothes Washer	8	40	$ 219.43	316	$ 1,755.48
Infrared Heating - 2-100-300 MBtu/hr	28	Variable	Variable	30,255	$ 71,030.16
Thermostat - Programmable - Ware, Ind, Rec, Agr	42	86	$ 147.35	3,629	$ 6,188.64
Distribution Contract Markets					
Custom - Agriculture	10	Variable	Variable	1,949,810	$ 1,309,546.14

Custom - DC	360	Variable	Variable	84,686,360	$ 183,896,208.54
Total	**448**	**126**	**$ 366.78**	**86,670,370**	**$ 185,284,728.96**

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit A, Tab 2, Appendix A, Schedule 13

a) For all categories of O&M expense that increase 2010-2011 greater than 3%, please provide a variance explanation.

b) Please provide the actual expense and Average annual increase in Total Net Utility Operating and Maintenance Expense 2007-2010.

c) Compare the Board approved 2011 Revenue Requirement and utility income to the Actual.

Response:

a) All categories of O&M expense changed by greater than 3% with the exception of Consulting and Company Used Gas. Explanations for these changes are provided at Exhibit B1.11 Attachment 1.

b)

Total Net Utility Operating and Maintenance Expense 2007-2010

Particulars ($ millions)	O&M Expense	$ Change
2007	318.041	
2008	322.732	4.691
2009	318.064	(4.668)
2010	349.373	31.309
Average increase 2007 - 2010		10.444

c) On an annual basis, for the purposes of setting delivery rates the Board approves a revenue figure as per Union's Incentive Regulation framework. As such there is not a Board-approved revenue requirement or utility income specific to 2011. Please see Exhibit A, Tab 2, Appendix A, Schedule 1 for the Sufficiency Calculation and Exhibit A, Tab 2, Appendix B, Schedule 1 for the Earnings Sharing Calculation.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit A, Tab 2 &
Exhibit A, Tab 2, Appendix B, Schedule 1

a) Please provide the December 31, 2011 audited consolidated financial statements of Union Gas Limited.

b) Please provide a non-utility elimination and provide the utility standalone financial statements.

c) Reconcile this to the second reference Schedule 1 and provide explanation of any variances.

d) If there are material differences, please restate the utility income used for ESM.

Response:

a) Please see the response at Exhibit B1.9 a).

b) Please see the response at Exhibit B1.9 c).

c) Please see the response at Exhibit B1.9 c).

d) No material differences exist.

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit A, Tab 2, Page 3 &
Exhibit A Tab 2, Appendix B, Schedule 1

a) Please provide the calculation of the 2011 benchmark ROE of 8.1% (pretax 10.10%).

b) Please provide Unions normalized ROE for each year of the IRM period

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Response:

a) Please see the response at Exhibit B1.9 e).

b) Union's weather normalized ROE before earnings sharing for each year of the IRM period is as follows:

2007 – 10.43%
2008 – 12.97%
2009 – 11.02%
2010 – 11.59%
2011 – 11.77%

UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe

Ref: Exhibit A, Tab 3, Pages 1-9 &
Exhibit A, Tab 3, Schedules 1-5

a) Please provide in tabular form a list of all allocators used for the disposition of the 2011 deferral account and ESM balances/amounts to the rate classes. Provide a summary as to why each allocator is appropriate and reflects cost causality.

b) For each Class please list the average volumes used to calculate the 2011 unit disposition rates and bill impacts for each disposition rate.

c) For residential customers please discuss why there are apparently different average volumes used for disposition rates and bill impacts e.g. 2048 m3, 2600 m3 etc.

Response:

a) The allocators used for the disposition of proposed 2011 deferral account, earnings sharing and other amounts are described at Exhibit A, Tab 3.

For allocation methodologies not yet approved by the Board, please refer to the response at Exhibit B1.12, parts a) and b). For all other balances, please refer to the response at Exhibit B1.12, part c).

b) The forecast volumes for the period October 1, 2012 to March 31, 2013 used to calculate the delivery and transportation related unit disposition rates for General Service classes Rate 01, Rate 10, Rate M1 and Rate M2 is shown at Exhibit A, Tab 3, Schedule 2, pages 1-2, column (g).

The forecast volumes for the period October 1, 2012 to March 31, 2013 used to calculate the commodity related unit disposition rates for Union South Sales Service classes is shown at Exhibit A, Tab 3, Schedule 2, page 3, column (g).

The actual 2011 volumes used to calculate the unit disposition rates for one-time adjustment for contract rate classes is shown at Exhibit A, Tab 3, Schedule 2, pages 4-5, column (g).

The bill impact for the average General Service customer in Rate 01, Rate 10, Rate M1 and Rate M2 is shown at Exhibit A, Tab 3, Schedule 3. The average bill impact for all remaining

delivery-related unit disposition rates for one-time adjustment by rate class is provided at Attachment 1.

c) Union calculates an average residential bill for Union North Rate 01 customers & Union South Rate M1 customers using an average annual consumption of 2,600 m^3.

As described at Exhibit A, Tab 3, Page 8, Union is proposing to dispose of 2011 amounts prospectively over the October 1, 2012 to March 31, 2013 time period. To calculate the bill impact of the disposition of 2011 amounts, Union applies the proposed unit rates to the volume of the average residential customer in Union North and Union South for the October to March period only.

For an average Rate 01 (Eastern Zone) residential customer in Union North, the average consumption volume for the October to March period is 2,048 m^3 (Exhibit A, Tab 3, Schedule 3, line 1, column b). For an average Rate M1 residential customer in Union South, the average consumption volume for the October to March period is 1,984 m^3 (Exhibit A, Tab 3, Schedule 3, line 9, column b).

Average Bill Impact by Rate Class for
Delivery-related Unit Disposition Rates for One-time Adjustment

Line No.	Particulars	Unit Disposition Rate (1) (cents/m^3)	2011 Average Volume (10^3m^3)	Bill Impact ($)
		(a)	(b)	(c) = (a x b)
1	Rate 20	(0.1454)	4,850	(7,053)
2	Rate 20T	(0.1087)	14,000	(15,224)
3	Rate 100	(0.0189)	110,000	(20,753)
4	Rate 25	(0.0805)	1,400	(1,126)
5	Rate M4	(0.1213)	2,800	(3,397)
6	Rate M5A	0.8615	3,400	29,292
7	Rate M7	0.2559	36,750	94,050
8	Rate M9	0.0119	20,000	2,370
9	Rate M10	0.1581	100	158
10	Rate T1	0.2122	80,000	169,799
11	Rate T3	0.0524	264,032	138,423

Notes:
(1) Exhibit A, Tab 3, Schedule 2, page 4, column (h).

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pages 2 and 3

Page 2, line 14 informs that Union's actual UDC was 2.0PJ in Union North.

a) Please explain why Union would not purchase gas index gas at Empress, transport it to the delivery point and sell the gas to cover the variable costs avoiding the UDC?

b) Please provide market values that demonstrate that the proposition in a) could not be done.

Response:

a) and b) Union is not permitted to engage in the contemplated activity. Union minimizes the cost of UDC by releasing the unfilled capacity to the secondary market.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pages 2 and 3

Table 1 on page 3 provides details on the collection of UDC in rates and actual costs incurred.

a) Please expand the table to provide the units of UDC forecasted (4.4 PJ and 2.0 PJ) and actual UDC incurred and the resulting unit rates.

b) Why are the unit rates different in the same delivery zone?

c) Please provide the calculation of resulting rates and any additional inputs not captured in the table.

Response:

a)

UDC Deferral Account by Operational Area

Line No.		Union North			Union South			Total Franchise Area
		($000's)	Volume (PJ)	Unit rate ($/gj)	($000's)	Volume (PJ)	Unit rate ($/gj)	($000's)
1	Forecast in Rates	6,489	4.4	1.47	117	0.2	0.59	6,606
2	Collected in Rates	6,217			146			6,363
3	UDC Costs Incurred	525	2	0.26	-	-	-	525
4	Variance	(5,692)			(146)			(5,838)
5	Interest	(43)			(1)			(44)
6	(Credit) / Debit to Operations Area	(5,735)			(147)			(5,882)

b) The UDC volumes in approved rates (4.4 PJs in the North and 0.2 PJ in the South) approved by the Board in EB-2005-0520 (Union's 2007 rate case) are fixed over the term of the

incentive regulation framework.

In the North, the UDC costs approved in 2011 rates reflect current TCPL tolls. As TCPL tolls increased since 2007, UDC costs approved in rates also increased proportionally.

In the South, the UDC costs approved in 2011 rates reflect the Trunkline tolls forecasted in EB-2005-0520 and the 2007 Board-approved UDC volumes. As Trunkline tolls have not changed materially since EB-2005-0520, UDC costs approved in rates have not changed significantly.

The actual unit rates are lower than forecast as Union releases the unfilled capacity to the secondary market to minimize the cost of UDC.

c) Please see the response above.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pages 4-8

Page 4, line 17 to Page 5, line 3 describes Union's determination of the deficit in the deferral account.

a) Does that determination include an allocation of $2,992M to shareholders representing 21% of the 2007 Revenue forecast of $15,829?

b) Please show the step-by-step derivation of Union's determined balance in tabular fashion with associated formulae.

Response:

a) No.

b) Exhibit A, Tab 1, Schedule 7, Column (a) shows the derivation of net deferral debit of $7.930 million. As noted on page 5 of Exhibit A, Tab 1, 90% of the net deferral debit or $7.137 million is shared with rate payers.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 1, pages 4-8

Figure 2 on page 8 shows the value of Short-Term Peak storage along with actual sales values.

a) Please provide the source of the Market Price shown in the graph?

b) Is that price published?

c) Does Union publish the price of its actual transactions on a timely basis? If so, how and when?

d) Please provide Union's rationale as to why the actual sales prices are so dramatically higher that the market values for most of the actual transactions.

Response:

a) Please see the response at Exhibit B10.1 a).

b) Please see the response at Exhibit B10.1 a).

c) Union publishes the price of our storage transactions on our website, on a semi annual basis in accordance with STAR.

d) Please see the response at Exhibit B10.1 c).

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Appendix A, Schedule 11
Exhibit A, Tab 4, Schedule 1

Schedule 11 refers to Revenue from Regulated Transportation of Gas.

a) Does Union received revenue from transportation of gas that is not reflected in this schedule?

b) Does Union receive revenue for transportation of gas associated with the non-utility storage business?

c) Does Union receive revenue for transportation of gas from any other source?

Response:

a) Union does not receive revenue from transportation of gas that is not reflected in EB-2012-0087 Exhibit A, Tab 2, Appendix A, Schedule 11.

a) A portion of the M16 Transportation revenues of Exhibit 1, Tab 2, Appendix A, Schedule 11, line 8 include revenues related to the transportation of gas associated with the non-utility storage business. Not all M16 Transportation is related to Union's non-utility storage business.

b) Union does not receive revenue for transportation of gas from any other source not reported in EB-2012-0087 Exhibit A, Tab 2, Appendix A, Schedule 11.

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Appendix A, Schedule 11
Exhibit A, Tab 4, Schedule 1

Schedule 11 provides the amount of revenue for each of the nine particular service categories.

a) Please expand the table with additional columns to include the actual values for 2007, 2008 and 2009.

b) To the extent that there are additional revenue categories that are identified in question 5, please add additional rows and provide the amount of revenue generated from these categories.

Response:

a) Please see Attachment 1.

b) No additional revenue categories were identified.

UNION GAS LIMITED
Revenue from Regulated Transportation of Gas
Years Ending December 31

Line No.	Particulars ($000's)	Board Approved	Actual				
		2007	2007	2008	2009	2010	2011
		(a)	(b)	(c)	(d)	(e)	(f)
	Transportation						
1	M12 Transportation	120,667	119,211	132,662	137,557	141,875	138,256
2	M12-X Transportation	-	-	-	-	-	1,477
3	M12 Transportation Overrun	-	2,601	1,171	1,124	546	17
4	C1 Long-term Transportation	2,900	2,093	5,790	6,642	6,288	7,570
5	C1 Short-term Transportation and Exchanges	3,742	9,030	23,266	29,781	32,555	44,228
6	C1 Rebate Program	(2,178)	(1,874)	-	-	-	-
7	M13 Transportation	864	649	529	462	386	323
8	M16 Transportation	553	240	474	609	610	642
9	Other Transportation Revenue	810	975	1,193	1,150	1,072	1,092
10	Total Transportation Revenue	127,358	132,925	165,085	177,325	183,332	193,605

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2, Appendix A, Schedule 11
Exhibit A, Tab 4, Schedule 1

Tab 4, Schedule 1 provides the transportation contracting analysis that Union provides as a result of the Settlement Agreement in EB-2005-0520. However, the analysis does not include TCPL - Empress to Parkway. Appended to these interrogatories is a replication of 2011-2012 Transportation Contracting Analysis contained in Schedule 1.

a) On the table appended, please fill in the row for the Route of TCPL Union Parkway that that has been added and shaded for the columns of (C) through (K) provided for the other routes.

b) In addition, for 2011-2012, please provide the values for additional columns (M) through (P) added and shaded. The definition of the columns are as follows:

i) (M) Planned Percentage of Supply Portfolio - Percent of Union South's total supply portfolio, delivered by pipeline contracts held by Union, for the year that was planned to be delivered by that Route.

ii) (N) Planned UDC as a Percentage of Route Total - Percent of the contracted pipeline capacity that was planned to remain empty in the gas supply plan.

iii) (O) Actual UDC as a Percentage of Route Total - Percentage of actual UDC for that Route that year.

iv) (P) Actual Percentage Used for Optimization - Percentage of pipeline capacity that was optimized to create Short Term Transportation and Exchange Revenue for that year.

v) (Q) Amount of Short Term Transportation and Exchange Revenue - Revenue generated from the Optimized Pipe contracts.

vi) (R) Amount of S-T Transportation and Exchange Revenue in Rates - Dollar value forecasted and embedded in rates.

c) For each of the years starting in 2007-2008 through to 2010-2011, please complete the expanded table as described in b). i) the sources for assumptions can be edited to the dates and exchange used in the development of the previous Transportation Contracting Analysis.

Response:

a) Please see Attachment 1.

b) Please see Attachment 1 for responses to part b) i) and ii). Actuals for 2011 are provided for part b) iii) – vi) in Attachment 2.

c) Expanded tables have not been prepared for 2007-2008 to 2010-2011 as this information is not relevant to this application.

Schedule 1
Response to B7.7 Attachment 1

Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	**Landed Cost $Cdn/Gj**	Point of Delivery	*Planned Percentage of Supply Portfolio*	*Planned UDC as a Percentage of Route Total*
(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	**(K)**	(L)	*(M)*	*(N)*
Dawn	Dawn	0.299	5.3521	0.0000	0.0000	0.0000	0.0000	5.35	**5.87**	Dawn	*5.4%*	*0%*
Vector (2011)	Chicago	0.054	5.1067	0.2397	0.0019	0.0618	0.3034	5.41	**5.93**	Dawn	*3.7%*	*0%*
Vector (2008)	Chicago	0.054	5.1067	0.2500	0.0019	0.0618	0.3137	5.42	**5.94**	Dawn	*23.9%*	*0%*
Trunkline/Panhandle	Trunkline Field Zone	(0.031)	5.0215	0.1900	0.0274	0.2139	0.4313	5.45	**5.98**	Ojibway	*7.3%*	*0%*
PEPL FZ-MichCon-St Clair	Panhandle Field Zone	(0.277)	4.7760	0.3083	0.0442	0.3893	0.7418	5.52	**6.05**	Dawn	*7.3%*	*0%*
Panhandle Longhaul	Panhandle Field Zone	(0.277)	4.7760	0.4251	0.0442	0.2813	0.7506	5.53	**6.06**	Ojibway	*9.2%*	*0%*
Alliance/Vector	CREC	(0.617)	4.4358	1.6991	(0.287)	0.2577	1.6694	6.11	**6.70**	Dawn	*28.2%*	*0%*
TCPL SWDA	Empress	(0.612)	4.4408	1.9430	0.1330	0.1079	2.1840	6.62	**7.27**	Dawn	*0.0%*	*0%*
TCPL Union CDA	*Empress*	*(0.612)*	*4.4408*	*2.3022*	*0.1577*	*0.1292*	*2.5891*	*7.03*	***7.71***	*Parkway*	*15.0%*	*0%*
TOTAL											*100.0%*	

Sources for Assumptions:

Gas Supply Prices (Col D): ICE Settlement; May 31, 2011

Fuel Ratios (Col G): Average ratio over the previous 12 months or Pipeline Forecast *(as existed at time of original analysis - June 2011)*

Transportation Tolls (Cols E & F): Tolls in effect on Alternative Routes at the time of Union's *Original* Analysis

Foreign Exchange (Col K) $1 US = $0.962 CDN

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056 GJ

Union's Analysis Completed: Jun-11 *(TCPL Union CDA Path added May 2012)*

Response to B7.7 Attachment 2

Route	Point of Supply	Point of Delivery	*Actual UDC as a Percentage of Route Total (%)*	*Actual Percentage Used for Optimization (%)*	*Amount of Short-Term Transportation and Exchange Revenue ($000s Cdn)*		*Amount of S&T Transportation and Exchange Revenue in Rates ($Cdn)*
(A)	(B)	(C)	*(D)*	*(E)*	*(F)*		*(G)*
Dawn	Dawn	Dawn	*N/A*	*N/A*	*N/A*		
Vector	Chicago	Dawn	*0%*	*4%*	*29*		
Trunkline/Panhandle	Trunkline Field Zone	Ojibway	*8%*	*51%*	*20*		
PEPL FZ-MichCon-St Clair	Panhandle Field Zone	Dawn	*0%*	*0%*	*-*		NOTE 1
Panhandle Longhaul	Panhandle Field Zone	Ojibway	*13%*	*0%*	*14*		
Alliance/Vector	CREC	Dawn	*0%*	*13%*	*208*		
TCPL SWDA (1)	Empress	Dawn	*N/A*	*N/A*	*N/A*		
TCPL Union CDA	Empress	Parkway	*0%*	*95%*	*11,277*	(2)	

Sources for Assumptions:

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056 GJ

Union's Analysis Completed: May 2012

Note 1 Embedded in rates is a level of transportation and exchange margin of $6.6 million. This figure cannot be broken out between transportation and exchanges or by transportation path.

Footnotes
(1) not a contract in Union's portfolio
(2) approximation

UNION GAS LIMITED

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

Reference: Exhibit A, Tab 2 page 5

Lines 8-9 describes the $6.4M reversal.

Please provide a calculation that shows the Earning Sharing impact of the original set-up of the deferral account and the Earning Sharing impact of the subsequent reversal.

Response:

In the 2009 earnings sharing calculation, the cost related to the original set-up of the Cumulative Under-recovery of the St. Clair Transmission Line was excluded from utility earnings as shown at EB-2010-0039, Exhibit A, Tab 2, Appendix B, Schedule 1 Corrected, Line 12, Column (c) and attached as Attachment 1.

The Board approved the earnings sharing amount in EB-2010-0039, Exhibit A, Tab 2, Appendix B, Schedule 1 Corrected and an additional credit of $0.334 million for future tax expense related to 2008 upon agreement by all parties in the Settlement Agreement.

The subsequent reversal of the Cumulative Under-recovery of the St. Clair Transmission Line has also been excluded from utility earnings for purposes of calculating earnings sharing at Exhibit A, Tab 2, Appendix B, Schedule 1, Line 11, Column (c).

UNION GAS LIMITED
Earnings Sharing Calculation
Year Ended December 31, 2009

Line No.	Particulars ($000s)	2009 (a)	Non-Utility Storage (b)	Adjustments (c)		2009 Utility (d)=(a)-(b)+(c)
	Operating Revenues:					
1	Operating revenue	$ 1,699,503	$ -	$ -		$ 1,699,503
2	Storage & Transportation	299,108	119,909	(1,874)	i	177,325
3	Other	35,760	-	(9,047)	ii	26,713
4		2,034,371	119,909	(10,921)		1,903,541
	Operating Expenses:					
5	Cost of gas	1,025,674	6,318	-		1,019,356
6	Operating and maintenance expenses	332,607	12,897	(1,646)	iii	318,064
7	Depreciation	194,485	7,312	-		187,173
8	Other financing	-	-	474	iv	474
9	Property and capital taxes	68,392	1,754	-		66,638
10		1,621,158	28,281	(1,172)		1,591,705
	Other					
11	Lobo C / Brantford-Kirkwall write off	(1,889)	-	-		(1,889)
12	Gain / (Loss) on sale of assets	(6,838)	(436)	6,402	v	0
13	Other	(1,094)	(1,094)			-
14	Gain / (Loss) on foreign exchange	(1,207)	(46)	-		(1,161)
15		(11,028)	(1,576)	6,402		(3,050)
16	Earning Before Interest and Taxes	$ 402,185	$ 90,052	$ (3,347)		$ 308,786
	Financial Expenses:					
17	Long-term debt					150,719
18	Unfunded short-term debt					606
19						151,325
20	Utility income before income taxes					157,461
21	Income taxes					28,767
22	Preferred dividend requirements					2,665
23	Utility earnings					126,029
24	Long term storage premium subsidy (after tax)					7,171
25	Short term storage premium subsidy (after tax)					7,540
26						14,711
27	Earnings subject to sharing					$ 140,740
28	Common equity					1,253,827
29	Return on equity (line 27 / line 28)					11.22%
30	Benchmark return on equity					10.47%
31	50% Earnings sharing % (line 29 - line 30, maximum 1%)					0.75%
32	90% Earnings sharing to ratepayer % (if line 31 = 1% then line 29 - line 30 - line 31)					0.00%
33	50% Earnings sharing $ (line 28 x line 31 x 50%)					4,732
34	90% Earnings sharing to ratepayer $ (line 28 x line 32 x 90%)					-
35	Total earnings sharing $ (line 33 + line 34)					4,732
36	Pre-tax earnings sharing (line 35 / (1 minus tax rate))					$ 7,063

Notes:

i) Remove out of period accounting of C1 Margin rebate related to 2007

ii)

Shared Savings Mechanism	(8,879)
Market Transformation Incentive	(500)
Accounting adjustment	332
	(9,047)

iii)

Donations	(446)
Remove out of period PST assessment related to prior periods	(1,200)
	(1,646)

iv) Customer deposit interest

v) Provision for Cumulative Under-recovery - St. Clair Transmission Line

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit A, Tab 1

Please file a table with the following columns, with one row for each of Union's rate classes, using the 2011 methodology for allocation of SSM:

a) 2011 DSM Budget $000
b) 2011 DSM Actual $000
c) Variance 2011 DSM Actual minus 2011 DSM Budget $000
d) % Change: 100 x [2011 DSM Actual divided by 2011 DSM Budget]
e) Proposed 2011 Low Income DSM Program $000
f) Proposed 2011 SSM $000
g) Proposed 2011 Market Transformation Incentive $000
h) Proposed 2011 Low Income Incentive $000
i) Proposed 2011 LRAM $000
j) Subtotal $000
k) Deferrals from 2010 $000
l) Total $000
m) % Change: 100 x [Total $000 divided by 2011 DSM Budget $000]

Response:

Please see Attachment 1.

UNION GAS LIMITED
2011 DSM Using 2011 Methodology

Line No.	Particulars ($000's)	DSM Costs in 2011 Rates	Actual DSM Costs	Account Balance	% change	2011 Incr. Low Income	2011 SSM	2011 Mrkt Transf	2011 Low Income Incentive	2011 LRAM	Subtotal	2010 LRAMVA	2010 SSM	Total	% change from DSM costs in 2011 Rates
		(a)	(b)	(c) = (b) - (a)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n) = (m-a) /a x 100
	South														
1	M1	7,612	8,351	739	9.7%	1,756	887	430	465	227	12,114	346	(32)	12,428	63.3%
2	M2	3,154	3,300	146	4.6%		498			188	3,986	322	8	4,316	36.8%
3	M4	2,391	987	(1,403)	(58.7%)		513			35	1,535	63	37	1,636	(31.6%)
4	M5	0	2,104	2,104			980			105	3,190	119	31	3,340	
5	M7	909	588	(320)	(35.3%)		610			15	1,214	28	59	1,301	43.1%
6	T1	1,484	4,364	2,880	194.1%		4,402			40	8,805	30	155	8,990	506.0%
7		15,549	19,694	4,145	26.7%	1,756	7,890	430	465	609	30,843	908	258	32,010	105.9%
	North														
8	Rate 01	2,269	2,268	(1)	(0.1%)	300	253	70	79	130	3,100	123	(12)	3,211	41.5%
9	Rate 10	1,951	846	(1,106)	(56.7%)		104			62	1,012	59	(1)	1,070	(45.2%)
10	Rate 20	1,308	573	(735)	(56.2%)		291			8	873	25	30	928	(29.1%)
11	Rate 100	2,112	834	(1,278)	(60.5%)		705			12	1,551	72	146	1,770	(16.2%)
12		7,640	4,521	(3,120)	(40.8%)	300	1,354	70	79	213	6,537	279	163	6,978	(8.7%)
13	Total	23,190	24,215	1,025	4.4%	2,056	9,243	500	544	822	37,380	1,187	421	38,988	68.1%

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit A, Tab 1

Please file a table that is the same as that requested in IGUA Interrogatory #1, but allocating SSM, Market Transformation and Low Income incentives using the 2012 methodology for allocation of SSM.

Response:

Please see Attachment 1.

UNION GAS LIMITED
2011 DSM Using 2012 Methodology

Line No.	Particulars ($000s)	DSM Costs in 2011 Rates	Actual DSM Costs	Account Balance	% change	2011 Incr. Low Income	2011 SSM (2012 Methodology)	2011 Mrkt Transf	2011 Low Income Incentive	2011 LRAM	Subtotal	True-Up 2010 LRAMVA	SSMVA	Total	% change from DSM costs in 2011 Rates
		(a)	(b)	(c) = (b) - (a)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n) = (m-a)/a x 100
	South														
1	M1	7,612	8,351	739	9.7%	1,756	2,629	445	462	227	13,869	346	(32)	14,183	86.3%
2	M2	3,154	3,300	146	4.6%		1,300			188	4,787	322	8	5,117	62.2%
3	M4	2,391	987	(1,403)	(58.7%)		546			35	1,568	63	37	1,669	(30.2%)
4	M5	0	2,104	2,104			890			105	3,099	119	31	3,249	
5	M7	909	588	(320)	(35.3%)		297			15	901	28	59	988	8.7%
6	T1	1,484	4,364	2,880	194.1%		1,658			40	6,061	30	155	6,246	321.0%
7		15,549	19,694	4,145	26.7%	1,756	7,319	445	462	609	30,285	908	258	31,451	102.3%
	North														
8	Rate 01	2,269	2,268	(1)	(0.1%)	300	852	55	82	130	3,687	123	(12)	3,798	67.4%
9	Rate 10	1,951	846	(1,106)	(56.7%)		358			62	1,266	59	(1)	1,324	(32.2%)
10	Rate 20	1,308	573	(735)	(56.2%)		314			8	896	25	30	950	(27.4%)
11	Rate 100	2,112	834	(1,278)	(60.5%)		400			12	1,246	72	146	1,464	(30.6%)
12		7,640	4,521	(3,120)	(40.8%)	300	1,924	55	82	213	7,095	279	163	7,536	(1.4%)
13	Total	23,190	24,215	1,025	4.4%	2,056	9,243	500	544	822	37,380	1,187	421	38,988	68.1%

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit A, Tab 1

Please file a table that contains the same information as the table requested in IGUA interrogatory #1, but calculated in cents per cubic meter using actual 2011 volumes rather than in total dollars. Please add two columns at the beginning of this table headed *"2011 delivery rate (¢/m3)"* and *"2012 delivery rate (¢/m3)"*, respectively.

Response:

Please see Attachment 1.

UNION GAS LIMITED
2011 DSM Using 2011 Methodology

Line No.	Particulars (cents/m^3)	2011 Delivery Rate (1)	2012 Delivery Rate (2)	DSM Costs in 2011 Rates	Actual DSM Costs	Account Balance	% change	2011 Incremental Low Income	2011 SSM	2011 Market Transformation	2011 Low Income Incentive	2011 LRAM	Subtotal	True-Up 2010 LRAMVA	SSMVA	Total	% change from DSM costs in 2011 Rates
		(a)	(b)	(c)	(d)	(e) = (d - c)	(f)	(g)	(h)	(i)	(j)	(k)	(l) = sum (d, g to k)	(m)	(n)	(o) = (l+m+n)	(p) = (o-c)/c x 100
	Union South																
1	Rate M1	13.0979	13.5523	0.2606	0.2858	0.0253	9.7%	0.0601	0.0303	0.0147	0.0159	0.0078	0.4146	0.0118	(0.0011)	0.4254	63.3%
2	Rate M2	4.6397	4.7790	0.2787	0.2916	0.0129	4.6%	-	0.0440	-	-	0.0166	0.3521	0.0285	0.0007	0.3813	36.8%
3	Rate M4	2.8915	2.6476	0.5405	0.2232	(0.3173)	(58.7%)	-	0.1159	-	-	0.0079	0.3471	0.0143	0.0084	0.3698	(31.6%)
4	Rate M5A	1.9105	2.3418	-	0.4122	0.4122		-	0.1921	-	-	0.0206	0.6248	0.0233	0.0061	0.6542	
5	Rate M7	2.2590	2.2167	0.3530	0.2285	(0.1245)	(35.3%)	-	0.2371	-	-	0.0060	0.4717	0.0108	0.0228	0.5053	43.1%
6	Rate T1	1.1403	1.1730	0.0327	0.0961	0.0634	194.1%	-	0.0969	-	-	0.0009	0.1939	0.0007	0.0034	0.1979	506.0%
7	Total Union South			0.1586	0.2008	0.0423	26.7%	0.0601	0.0805	0.0147	0.0159	0.0062	0.3145	0.0093	0.0026	0.3264	105.9%
	Union North																
8	Rate 01	15.2175	15.5129	0.2504	0.2502	(0.0001)	(0.1%)	0.0331	0.0279	0.0077	0.0088	0.0144	0.3421	0.0135	(0.0013)	0.3543	41.5%
9	Rate 10	5.2320	4.7164	0.5732	0.2484	(0.3248)	(56.7%)	-	0.0306	-	-	0.0182	0.2973	0.0173	(0.0004)	0.3142	(45.2%)
10	Rate 20	1.4795	1.3951	0.2069	0.0907	(0.1162)	(56.2%)	-	0.0461	-	-	0.0013	0.1381	0.0039	0.0047	0.1467	(29.1%)
11	Rate 100	0.7110	0.6802	0.1116	0.0440	(0.0675)	(60.5%)	-	0.0373	-	-	0.0007	0.0820	0.0038	0.0077	0.0935	(16.2%)
12	Total Union North			0.2026	0.1199	(0.0827)	(40.8%)	0.0331	0.0359	0.0077	0.0088	0.0056	0.1733	0.0074	0.0043	0.1850	(8.7%)
13	Grand Total			0.1708	0.1783	0.0076	4.4%	0.0537	0.0681	0.0131	0.0142	0.0061	0.2753	0.0087	0.0031	0.2872	68.1%

Notes:
(1 EB-2010-0148, Rate Order, Working Papers, Schedule 3, Page 2, column (r). Rates are calculated using 2011 forecast volumes as approved in EB-2010-0148.
(2 EB-2011-0025, Rate Order, Working Papers, Schedule 3, Page 1, column (l). Rates are calculated using 2012 forecast volumes as approved in EB-2011-0025.

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit A, Tab 1

Please file a table that contains the same information as that requested in IGUA Interrogatory #2, but calculated in cents per cubic meter using actual 2011 volumes rather than in total dollars. Please add two columns at the beginning of this table headed *"2011 delivery rate (¢/m3)"* and *"2012 delivery rate (¢/m3)"*, respectively.

Response:

Please see Attachment 1.

UNION GAS LIMITED
2011 DSM Using 2012 Methodology

Line No.	Particulars (cents/m^3)	2011 Delivery Rate (1)	2012 Delivery Rate (2)	DSM Costs in 2011 Rates	Actual DSM Costs	Account Balance	% change	2011 Incremental Low Income	2011 SSM (2012 Methodology)	2011 Market Transformation	2011 Low Income Incentive	2011 LRAM	Subtotal	True-Up 2010 LRAMVA	SSMVA	Total	% change from DSM costs in 2011 Rates
		(a)	(b)	(c)	(d)	(e) = (d - c)	(f)	(g)	(h)	(i)	(j)	(k)	(l) = sum (d, g to k)	(m)	(n)	(o) = (l+m+n)	(p) = (o-c)/c x 100
	Union South																
1	Rate M1	13.0979	13.5523	0.2606	0.2858	0.0253	9.7%	0.0601	0.0900	0.0147	0.0159	0.0078	0.4743	0.0118	(0.0011)	0.4850	86.2%
2	Rate M2	4.6397	4.7790	0.2787	0.2916	0.0129	4.6%	-	0.1148	-	-	0.0166	0.4229	0.0285	0.0007	0.4521	62.2%
3	Rate M4	2.8915	2.6476	0.5405	0.2232	(0.3173)	(58.7%)	-	0.1234	-	-	0.0079	0.3545	0.0143	0.0084	0.3772	(30.2%)
4	Rate M5A	1.9105	2.3418	-	0.4122	0.4122		-	0.1743	-	-	0.0206	0.6071	0.0233	0.0061	0.6365	
5	Rate M7	2.2590	2.2167	0.3530	0.2285	(0.1245)	(35.3%)	-	0.1156	-	-	0.0060	0.3501	0.0108	0.0228	0.3837	8.7%
6	Rate T1	1.1403	1.1730	0.0327	0.0961	0.0634	194.1%	-	0.0365	-	-	0.0009	0.1334	0.0007	0.0034	0.1375	321.0%
7	Total Union South			0.1586	0.2008	0.0423	26.7%	0.0601	0.0746	0.0147	0.0159	0.0062	0.3145	0.0093	0.0026	0.3207	102.3%
	Union North																
8	Rate 01	15.2175	15.5129	0.2504	0.2502	(0.0001)	(0.1%)	0.0331	0.0940	0.0077	0.0088	0.0144	0.4082	0.0135	(0.0013)	0.4204	67.9%
9	Rate 10	5.2320	4.7164	0.5732	0.2484	(0.3248)	(56.7%)	-	0.1053	-	-	0.0182	0.3719	0.0173	(0.0004)	0.3888	(32.2%)
10	Rate 20	1.4795	1.3951	0.2069	0.0907	(0.1162)	(56.2%)	-	0.0497	-	-	0.0013	0.1417	0.0039	0.0047	0.1503	(27.4%)
11	Rate 100	0.7110	0.6802	0.1116	0.0440	(0.0675)	(60.5%)	-	0.0211	-	-	0.0007	0.0658	0.0038	0.0077	0.0774	(30.6%)
12	Total Union North			0.2026	0.1199	(0.0827)	(40.8%)	0.0331	0.0510	0.0077	0.0088	0.0056	0.1733	0.0074	0.0043	0.1998	(1.4%)
13	Grand Total			0.1708	0.1783	0.0076	4.4%	0.0537	0.0681	0.0131	0.0142	0.0061	0.2753	0.0087	0.0031	0.2872	68.1%

Notes:
(1 EB-2010-0148, Rate Order, Working Papers, Schedule 3, Page 2, column (r). Rates are calculated using 2011 forecast volumes as approved in EB-2010-0148.
(2 EB-2011-0025, Rate Order, Working Papers, Schedule 3, Page 1, column (l). Rates are calculated using 2012 forecast volumes as approved in EB-2011-0025.

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit A, Tab 1, page 14.

While not proposing in this application to dispose of costs associated with implementation of GDAR amendments, Union has provided information on its expected costs for such implementation. Union explains these costs as including capital costs to modify Union's customer information system so that it has the functionality required to implement Union's updated policies and practices.

a) Please explain precisely what new customer service information system functionality and associated modifications are anticipated to be required.

b) Please indicate which rate classes these expenditures would be allocated to.

Response:

a) The following changes to the Conditions of Service were implemented on March 5, 2012, for residential customers:

Bill Issuance and Payment

Union Gas will now accept credit cards for bill payments. The inclusion of credit cards as a payment type required the set-up of the Union Gas web portal through Paymentus corporation as well as modifications to the Union Gas website and IVR.

Union Gas will provide customers requiring emergency financial assistance a total of 21 days to secure social assistance before a collection action is initiated for non-payment. This was a process change and did not require any functionality changes.

Union Gas has extended the bill payment period for the Late Payment Charge to be applied from 16 to 20 days. This change was implemented effective January 1, 2012. This was accomplished by modifying rules applied to account charges within the Customer Service Information System.

Correction of Billing Errors

In the rare event that an adjustment must be made to the charges that have been billed to a customer's account, Union Gas will provide additional explanations on the customer's bill as to the reasons for the adjustment. This required modifications to our customer service system

to identify those adjustments considered significant. In addition changes were made to Union's bill print functionality.

Equal Billing Plan

Customers can now join the Equal Billing Plan ("EBP") during any month of the year. Union Gas will clearly explain how the plan works, including why Union will occasionally adjust monthly installments to match actual gas usage. The customer service information system functionality for EBP was modified to extend the eligibility of the program to every month of the year. Significant changes were also required to ensure there is an accurate calculation of a customer's EBP amount at any time of the year and also in unique circumstances such as new housing when insufficient usage history is available. Additional modifications were required to Union Gas' website and IVR system.

Disconnection for Non-Payment

Union Gas will provide 10 days written notice of a pending disconnection for non-payment of gas charges. The notification will also describe payment options to avoid the disconnection of gas services. Significant modifications were introduced to issue a disconnection notice and to change collection processes within the customer service information system to issue as well as cancel a disconnection order if customer payments or payment arrangements are received.

Security Deposits

Customers who are required to pay a security deposit will now be given the choice to pay the deposit in installments of up to six months duration. Union Gas will continue to provide customers the choice of waiving the required security deposit if they enrol in both the Equal Billing Plan and the Automatic Payment Plan.

Security deposits are designed to cover two months of gas bills. To estimate the total of these two bills, Union Gas will now review two average bills from the past year instead of the two highest bills. These two modifications involved extensive changes to the customer service information system to calculate a security deposit using a two month average rather than the two highest months and to introduce installment functionality to allow the security deposit to be billed over six months. Modifications were also required to the website, the IVR and bill print functionality.

Arrears Management Programs

Customers who have entered into a payment arrangement for an overdue account will be notified in advance when payments are due. Customers will also be given 10 days notice of disconnection if they fail to meet the obligations of the arrangement. To comply with this new rule, adjustments were made to the collection processes that occur within the customer service information system as well as our outbound collection system.

Customers who have security deposits on their accounts may receive additional opportunities to pay their arrears before Union issues a notice of disconnection for non-payment. This change also required modifications to the collection processes within the customer service information system.

b) Union has not finalized the allocation methodology for these costs for 2012. Given the nature of the costs, Union anticipates that the costs will be allocated to general service customers.

UNION GAS LIMITED

Answer to Interrogatory from
Industrial Gas Users Association ("IGUA")

Reference: Exhibit A, Tab 2, Appendix B, Schedule 1

Please confirm Union's net utility earnings, both in dollars and in percentage, after earnings sharing as proposed.

Response:

Union's net utility earnings after earnings sharing is $137.3 million or 10.65%.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, page 3

Please explain why the amount collected in rates in Union North was less than the amount included in the 2011 Board-approved rates while the amount collected in Union South was higher than the amount included in the 2011 Board-approved rates. Is the difference related solely to the difference in volumes between actual and forecasted?

Response:

Yes. Please see the response to Exhibit B5.1

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Figure 2

The actual sale shown in Figure 2 in August, 2011 appears to be significantly below the market price. Please confirm that the sale of this storage was not to an affiliate and that it was not related to any agreement between the purchaser(s) and any affiliate of Union Gas.

Response:

Confirmed.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, page 25

a) Please identify the OM&A purchases that were previously exempt and for which tax credits are now restricted that resulted in the 2011 tax cost of $0.715 million.

b) Please confirm that the increased compressor fuel cost of $0.754 million does not include any fuel used for non-regulated activities.

Response:

a) Please see the response at Exhibit B1.8 b).

b) Confirmed.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 2

Is the calculation of utility earnings and earnings sharing consistent with the methodology used to calculated to the 2010 earnings sharing in EB-2011-0038? If not, please explain any differences.

Response:

The calculation of utility earnings and earnings sharing is consistent with the methodology used to calculate the 2010 earnings sharing in EB-2011-0038.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 2, page 3

Please show the calculation of the benchmark return on equity of 8.10%.

Response:

Please see the response at Exhibit B1.9 e).

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 2, pages 8-9

a) What is Union's normalized actual return on equity for 2011?

b) At what level would the X factor have had to been in 2011 to result in a normalized return on equity equal to the benchmark ROE of 8.10%?

Response:

a) The weather normalized ROE before earnings sharing for 2011 is 11.77%.

b) The X factor would have had to be 9.46%.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 3

a) Are all of Union's allocation proposals consistent with the most recent approved allocation methodology for each account? If not, or if some accounts have not been approved for disposal before now, please provide details.

b) Did Union consider other alternatives than those shown for the allocation of any accounts that have not previously been approved by the Board? If yes, please provide the alternatives considered and the reasons they were rejected in favour of the proposals.

Response:

a) Please see the response at Exhibit B1.12 a) and c).

b) Please see the response at Exhibit B1.12 b).

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Schedule 6

a) Please provide the calculations and all assumptions used in the calculation of the demand related costs for the return, depreciation and income taxes shown for 2011.

b) Please explain why each of the demand related costs shown for 2011 are the same as for 2010.

Response:

a) Please see the response at Exhibit B6.1 a).

b) Please see the response at Exhibit B1.1 b).

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Schedules 6 and 7

Please explain why the total demand related costs shown on Schedule 6 at line 13 are labelled as O&M costs on Schedule 7 at line 5.

Response:

The demand costs shown at Schedule 6, Line 13, column c) represent the $2.261 million revenue requirement associated with 7.9 PJ of excess utility storage space. On Schedule 7, Line 5 the revenue requirement of $2.261 million is shown as O&M to recognize that this cost is charged to Union's non-utility storage operations for its use of excess utility storage space.

UNION GAS LIMITED

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

Ref: Exhibit A, Tab 1, Schedule 7

a) Please show the impact on the calculation of the excess for 2011 of (7,930) if the Board approved figure of $15,829 is reduced to reflect the removal of the 21% non-utility share built into base rates.

b) What is the impact on the ratepayer portion of the calculation in part (a)?

Response:

a) and b) Please see the response at Exhibit B1.1 a).

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab1, page 7 and, page 8, Figure 2

a) Please explain what the data source is for the "Market Price" shown.

b) Please explain briefly what the "Market Price" data shown actually means.

c) Please explain why there are any sales below the "Market Price," for example the sales at August 13, 2011 in the figure.

d) The data show only nine dates on which short-term firm peak storage sales were made in 2011. Is this a typical level of activity on an annual basis?

e) Please provide any additional non-confidential information available with regard to the sales made on each date as shown in Figure 2, i.e., type of transaction, space, deliverability, unit price, whether counterparty was affiliated or a competitor, etc.

f) In general, to what does Union attribute its general ability to usually sell the subject services at or above the "Market Price"?

g) Does Union agree that as market values of firm peak storage services decrease, there is no necessary reasons why the number of storage sales should decrease?

Response:

a) The values represent the difference in values between the summer and winter months, as traded on the NYMEX, plus the Dawn basis, adjusted by Union for time value of money and the cost to cycle storage. The prices are intended to reflect the value of short-term peak storage at Dawn.

b) The market price data is meant to give an approximate value of short-term peak storage service at Dawn over time.

c) The market price is an indication of what the customer would pay according strictly to the market price spreads. In reality, customers may value the storage differently after considering their own needs, contract terms and views of the market.

d) Yes, 2011 represented a typical level of activity.

e) Please see Attachment 1.

f***)*** Please see the response to part c) above.

g) Agreed.

UNION GAS LIMITED
Southern Operations Area
Summary of Short Term Firm Peak Storage Contracts Signed in 2011

Line No.	Service Type	Storage Space (GJs)	Firm Deliverability (GJ/day)	Price ($US/MMBtu)	Affiliate (Y/N)
		(a)	(b)	(c)	(d)
1	Short Term Firm Peak Storage Contract #1	1,055,056	12,661	0.70	N
2	Short Term Firm Peak Storage Contract #2	1,055,056	12,661	0.77	N
3	Short Term Firm Peak Storage Contract #3	1,055,056	12,661	0.71	N
4	Short Term Firm Peak Storage Contract #4	2,110,112	25,321	0.71	N
5	Short Term Firm Peak Storage Contract #5	1,055,056	12,661	0.60	N
6	Short Term Firm Peak Storage Contract #6	1,055,056	12,661	0.80	N
7	Short Term Firm Peak Storage Contract #7	2,110,112	25,321	0.68	N
8	Short Term Firm Peak Storage Contract #8	527,528	6,330	0.48	N

Note: Firm deliverability is 0 in the months of March and April.

UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

Reference: Exhibit A, Tab 2, page 3 and Appendix B, Schedule 1

a) Please show how the 8.10% benchmark ROE was calculated.

b) Please provide the actual normalized ROE for 2011.

c) Please provide the X-factor that would have been required to set normalized actual 2011 ROE equal to 8.10%.

Response:

a) Please see the response at Exhibit B1.9 e).

b) Please see the response at Exhibit B6.5 b).

c) Please see the response at Exhibit B9.6 b).